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FUNCTION OF NATURAL GAS
IN THE
PRODUCTION OF OIL

FUNCTION OF NATURAL GAS IN THE PRODUCTION OF OIL

By

H. C. MILLER

Senior Petroleum Engineer, U. S. Bureau of Mines

A Report of the

U. S. BUREAU OF MINES
DEPARTMENT OF COMMERCE

In Cooperation with the

Division of Development and Production Engineering
of the
American Petroleum Institute

Based on Data Gathered and Reported by the

Kansas and Oklahoma; Pacific Coast; Rocky Mountain; and Texas and Louisiana Regional Committees of the Gas Conservation Committee of the American Petroleum Institute

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By H. C. MILLER[2]

INTRODUCTION

In its effort to increase efficiency of oil production, the American Petroleum Institute in 1927 undertook to collect data relative to the function of gas in the production of oil. A committee known as the Gas Conservation Committee of the American Petroleum Institute was appointed by Mr. E. W. Clark, President of the Institute, to make the neces sary arrangements for gathering these data. The personnel of the committee was:

E. W. Marland, Chairman

Henry McGraw	Sid H. Keoughan
Wm. S. Farish	J. Edgar Pew
Thomas A. O'Donnell	L. P. St. Clair

The Gas Conservation Committee met at Colorado Springs on September 11 and 12, 1927, and unanimously adopted the following resolution:

WHEREAS, This Committee has been created by the American Petroleum Institute and charged with the duty of devising and suggesting to the Board of Directors of the Institute " such measures as will enable the industry, while continuing to meet the consumption requirements for petroleum and its products, to conserve in its natural state such reserves of petroleum as may not be required for consumption."

AND WHEREAS, This Committee's recommendations should be based on all the technical and scientific data that can be made available to it.

Now, Therefore, Be it Resolved, That the Chairman of this Committee be, and he hereby is, authorized and directed

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[2] Senior petroleum engineer, U. S. Bureau of Mines.

to appoint, or obtain the appointment of, a Technical Sub-Committee to gather, collate and report back to this Committee all available information, including the opinions of qualified scientists and engineers, regarding the importance of natural gas in the conservation and production of petroleum, and the best means for its most efficient utilization.

And, Be it Further Resolved, That the members of the American Petroleum Institute and of the petroleum industry in general be, and they hereby are, requested to coöperate in every reasonable manner with the Technical Sub-Committee so created, by making available to it their pertinent data and such qualified men as can be of the greatest assistance.

Pursuant to the above resolution and to carry out its instructions, the Chairman appointed the following district sub-committee chairmen:

M. E. Lombardi, Pacific Coast
Max W. Ball, Rocky Mountain
John R. Suman, Texas and Louisiana
W. P. Haseman, Kansas and Oklahoma
Earl Oliver, General Secretary

These chairmen in turn organized regional committees which were instructed to collect data and information as called for by the resolution. The chairmen were further instructed to be prepared to report their findings at a meeting to be held in Ponca City, Okla., on October 17, 1927. At this meeting was gathered the membership of the American Petroleum Institute Gas Conservation Committee, and approximately 250 oil company executives and operators, officials of the Institute, attorneys, petroleum engineers, Government officials, and scientists, to consider and discuss the reports which were presented.

Regional sub-committee chairmen were called upon to read the summaries of their respective reports. These were presented by the following men:

John R. Suman, for Texas and Louisiana
G. C. Gester, for Pacific Coast
Fred E. Wood, for Rocky Mountain
W. P. Haseman, for Kansas and Oklahoma

Upon completion of the delivery of the summaries, the Chairman, Mr. E. W. Marland, requested the four regional chairmen to prepare a brief combined summary of the four summaries, for the meeting on the following morning. On account of the mass of data submitted and the short time available for the preparation of the summary, this report was submitted as a preliminary summary only, and by no means covered entirely the study of gas conservation made by the committees. This preliminary summary, prepared in such form as to constitute a short answer to three general questions submitted by the Technical Sub-Committee, represented the outstanding principles that were developed at greater length in the several district committee summaries. The committee chairmen were of the opinion that a more comprehensive summary should be prepared and submitted as soon as possible after an exhaustive study of the respective reports had been made.

Question 1.—State the Importance of Natural Gas in the Production of Petroleum.

Answer.—It is the conclusion of all committees that the conservation of gas in the production of oil is of paramount importance. The various reports brought out the following points:

(A) Gas is the chief expulsive agent in the majority of oil fields. It is recognized, however, that there are other expulsive forces, among the most important of which is the natural water drive.

(B) The amount of gas dissolved in crude oil is in direct proportion to gas pressure.

(C) Natural gas dissolved in crude oil reduces the viscosity of the oil in proportion to the amount and character of the gas dissolved.

(D) Natural gas in solution reduces the surface tension of the oil.

(E) Friction of oil passing through the sand is materially reduced through reduction of viscosity.

(F) Any reduction in viscosity and surface tension means reduction of the forces tending to retain the oil in the sands.

(G) Reduction in the amount of gas dissolved in crude oil as a result of reduction in rock pressure increases the viscosity. Therefore waste of gas indicates decrease in ultimate production.

(H) The comparison of production decline curves of wells shows a better sustained production of oil in wells where gas is efficiently used. By such efficient methods there is produced a longer period of flowing life, a more economical production, and, in the majority of cases, less gas is produced per barrel of oil.

Question 2.—Enumerate Your Opinions of the Best Means for the Most Efficient Utilization of Gas.

Answer.—Oil should be produced in such a way as to retain in the sand, throughout the life of the field, the maximum percentage of the original gas energy. Repressuring cannot reproduce original conditions, as evidenced by laboratory results and indicated by results in the field. Data presented indicate that no one method of producing wells is equally applicable to all fields or to all wells in the same field, or even to adjoining wells in the same lease, or to all periods in the life of the same well. The conservation of gas in flowing and pumping wells is a problem for individual study and field tests for which no one rule or set of rules can be prepared. The problem of proper conservation of gas in the production of oil should, therefore, be assigned to the petroleum engineer to solve by analysis and experimentation.

To obtain the most efficient use of gas energy and keep the recovery gas-oil ratio low, various producing practices, all of which are not always successful, are in use. They are:

(A) Correct spacing of wells and systematic drilling program.
(B) The application of pressure control.
(C) Repressuring, gas drive, etc.
(D) Gas and air lift flowing methods.
(E) Suitable pumping equipment, properly applied.

Natural gas is more effective for repressuring than air or other available gases:

(1) Carbon dioxide is soluble to a greater extent than air, natural gas, or flue gas, but it is probably not available in sufficient quantities for repressuring. Air is less soluble in crude oil than natural gas and probably oxidizes the oil, resulting in an increase in viscosity and leaving a residue in the sand tending to clog the pores.

(2) Introduction of air usually results in corrosion of the casing and tubing as a result of the action of oxygen brought into contact with moisture. Under certain conditions air introduced into the sand forms an explosive mixture and renders the gas produced unfit for field purposes.

Question 3.—State Comparative Advantages in Gas Utilization of an Ideal Coöperative Development of an Oil Pool as Compared to Typical Non-Coöperative Competitive Drainage Practice.

Answer.—

(A) Permits most efficient application of methods to conserve and utilize gas, and therefore permits greater ultimate recovery.

(B) Permits more satisfactory spacing and distribution of wells.

The regional sub-committee chairmen met again in Chicago on December 2, 1927, and reiterated their opinion that the prevention of waste of gas is of paramount importance in connection with the economical production and conservation of oil. Thereupon the Committee on Gas Conservation formulated its final report for presentation to the Board of Directors of the American Petroleum Institute, in which they suggested that appropriate resolutions be passed, calling upon the industry to adopt every reasonable and practical means to effect the conservation of natural gas in oil-bearing formations in the interest of economical production costs, increased ultimate recovery, and conservation of petroleum supplies to meet the demands of consumption.

The report of the Gas Conservation Committee was accepted by the Directors on December 8, 1927, thereby placing the American Petroleum Institute on record as favoring the control and efficient utilization of natural gas occurring with oil.

In 1928 the data collected by the four regional committees of the Institute's Gas Conservation Committee were turned over to the newly created Division of Development and Production Engineering of the American Petroleum Institute. The division proposed publication of these data, and a coöperative agreement between the Bureau of Mines and the American Petroleum Institute was made, whereby the Bureau of Mines was to prepare the data for publication as a coöperative report by the Bureau of Mines and the American Petroleum Institute.

The writer was assigned the duties of reviewing, revising, and combining all data collected by the several committees and collecting such other data as he deemed necessary for presentation in this report. The original sub-committee data have since been greatly augmented by correspondence with certain committee members and others; by extracting pertinent data from recently published articles on oil production and gas conservation; and by short papers requested of, and prepared by, various qualified scientists.

This report has been prepared in two parts. Part I summarizes the opinions of petroleum engineers, gained from experience in handling oil and gas wells in the United States, in regard to the importance of natural gas in the recovery of oil. Part I also includes descriptions of methods for controlling gas and oil production to gain the greatest ultimate recovery of oil from a field. Part II is a summary of available facts and conclusions concerning the properties and action of mixtures of oil and gas in underground formations.

ACKNOWLEDGMENTS

This report was prepared under the guidance and direction of E. G. Gaylord, Chief Petroleum Engineer, Standard Oil Co. of California, who represented the Division of Development and Production Engineering of the American Petroleum Institute; H. H. Hill, former Chief Petroleum Engineer of the Bureau of Mines; and H. C. Fowler, Acting Chief Engineer, Petroleum and Natural-Gas Division of the Bureau of Mines.

John L. Rich, Consulting Geologist, aided in editing the sections on the geology of petroleum, and M. J. Gavin of the Bureau of Mines gave valuable suggestions relating to the chemistry of petroleum.

The American Petroleum Institute, the Bureau of Mines, and the writer wish to express their appreciation to the members of the committees, and to the engineers and scientists who collected and contributed the valuable data herewith made public. The many operators and oil companies who contributed data, some of which are of a confidential nature, are to be commended for consenting to the publication of the general results and conclusions based upon these data.

The large number of men comprising the regional committees makes it impossible to acknowledge their individual contributions where appearing in the text. Credit is extended, however, by footnote references to authors of pub-

lished articles, and to the authors of scientific papers. Many of these papers were written at the request of the writer, who feels deeply indebted to those scientists who gave so freely of their knowledge and time.

W. N. Lambert made the drawings, and Elsie A. Miller typed the manuscript.

Acknowledgment is made to John R. Suman, Director of the Humble Oil and Refining Co. and Chairman of the Division of Development and Production Engineering, American Petroleum Institute; T. E. Swigart, Chief Production Engineer, Shell Oil Co. of California, and Chairman of the Publications Committee of the American Petroleum Institute; W. R. Boyd, jr., Executive Vice-President, American Petroleum Institute; and H. C. Fowler, A. L. Foster, K. B. Nowels, and C. P. Bowie, of the Bureau of Mines, who read the manuscript and made helpful suggestions.

PART I

IMPORTANCE OF NATURAL GAS IN THE RECOVERY OF OIL

AND

FIELD METHODS OF CONTROLLING GAS AND OIL PRODUCTION TO GAIN THE GREATEST ULTIMATE RECOVERY

DEFINITIONS

Special terms are necessarily used in discussing problems of petroleum production engineering. Many of these terms are relatively new and not in common usage throughout the United States. The following definitions of terms used in this paper are given to insure against possible misunderstanding in the discussions which follow.

1. Gas-oil ratio.—The number of cubic feet of gas produced per barrel of oil by a well.
2. Reservoir gas-oil ratio.—The number of cubic feet of gas per barrel of oil originally in the reservoir.
3. Recovery gas-oil ratio.—The number of cubic feet of gas produced from the reservoir per barrel of oil.
4. Circulated gas-oil ratio.—The number of cubic feet of gas introduced into the well for gas-lift operations, per barrel of oil lifted.
5. Effective back pressure.—The pressure at a given point on the face of the oil-bearing formation in a well. Due to the great thickness of some oil zones, particularly in California, the effective back pressure in the lower part of the oil zone may be as much as several hundred pounds per square inch more than the effective back pressure in the upper part. For that reason the term "Mean effective back pressure" is used to indicate the average effective back pressure on the series of oil sands comprising the productive zone.
6. Injected gas.—The gas put into an oil-producing sand for the purpose of maintaining or restoring rock (formation) pressure or for storage.
7. Pressure control.—The adjustment of pressures within a well to obtain the most efficient and economical utilization of the energy in the natural gas under pressure in the oil sands.

8. Flow bean.—A nipple or restriction that is placed in the flow line from wells to restrict and control the rate of flow of gas and oil from the wells. Sometimes called choker or flow nipple.
9. Deferred production.—Oil production held back in the producing formation as the result of the application of pressure control.
10. Controlled production.—Production of oil under the application of pressure control.
11. Stopcocking.—A production method for controlling gas pressures in oil wells by keeping the well closed in and the gas confined except during stated intervals when the oil is flowed or pumped.
12. Jamin effect.—The resistance offered to flow by alternating globules of liquid and bubbles of gas in channels of capillary dimensions.

THE ORIGIN AND MODE OF FORMATION OF PETROLEUM AND ITS MIGRATION AND ACCUMULATION

In a general way petroleum and natural gas are hydrocarbons occurring in and derived from the component materials of the earth's crust.

The crust of the earth is made up of three types of rocks—sedimentary, igneous, and metamorphic. The sedimentary rocks, with which natural hydrocarbons are almost exclusively associated, are those which have been formed by the accumulation of detritus derived from the wasting away of the land, transported by streams or other agencies, and deposited, mainly under water, in seas or lakes or spread out in alluvial plains along the streams. Igneous rocks are those which have at some time been in a molten condition, such as granite or lava. Metamorphic rocks are those, whether igneous or sedimentary, which have been profoundly altered by subjection to great heat and pressure while deeply buried in the earth.

Inasmuch as it is possible, chemically, to form hydrocarbons by certain reactions with metallic carbides, some investigators have thought that petroleum may have had an inorganic origin, having been formed in connection with igneous or volcanic activity. The evidence, however, is so overwhelmingly against the inorganic theory that almost all students of the subject now agree that organic materials which have become buried with the sedimentary rocks are the true source of petroleum and natural gas.

SEDIMENTARY ROCKS AS THE SOURCE OF MATERIALS FROM WHICH PETROLEUM IS GENERATED

Sedimentary rocks are composed mainly of shale, sandstone, and limestone. Shale is merely clay or mud, more or less compacted. Limestone is composed mainly of the remains of lime-secreting organisms, which may be microscopic in size or in larger forms such as corals or shellfish.

The sedimentary rocks are commonly arranged in more or less distinct layers or strata caused by the sorting action of waves and currents and by differences in the nature of materials supplied to the sea at various times. Shale and limestone are relatively compact and impervious, while sandstone is porous and capable of holding a considerable percentage of fluids. The shales and limestone contribute most of the source materials for petroleum, while the sandstones afford the most common reservoirs.

That large quantities of organic matter become buried with the sedimentary rocks is obvious. Vegetable débris of all sorts is carried into the sea by rivers; organic compounds in solution are also borne by the rivers and possibly precipitated in the sea by chemicals encountered there; leaves and spores of plants are blown into the water by the winds; shallow waters support a rich aquatic vegetation; and, finally, the water is swarming with animal organisms, large and small, the remains of which, in part, ultimately become buried with the sediments.

Microscopic examination of organic shales, such as oil shales, reveals large quantities of spores, remains of algæ, of insects, fishes, and many other forms of life, besides considerable quantities of a formless organic substance, sometimes called kerogen, which is probably a comminuted mixture of all of these. The organic constituents of the oil shales can be partly converted into petroleum by heating, as is done in the recovery of oil from oil shales.

The limestones, being made up mainly of the remains of organic life, also no doubt contributed to the organic débris which later might be converted into petroleum. In fact, samples of calcareous oozes (which are the early stages in the formation of limestone), now being studied under the auspices of the American Petroleum Institute, almost without exception yield small quantities of petroleum upon distillation. In California during Tertiary times tremendous thicknesses of more or less purely organic materials were deposited in the sea which occupied portions of that State. Organic shales, or shales consisting of at least 50 per cent by volume of fossil organisms, are exceedingly widespread. They are not confined to the rocks of any one geological period, but are found in vast quantity in rocks ranging in age from Cretaceous to Pleistocene, and in metamorphosed condition are found in even much older strata than Cretaceous.

The organisms preserved in these shales are of varied character, but fall in two distinct classes, siliceous and calcareous. To the first belong the diatoms, radiolarians, and silico-flagellates. To the second, or calcareous class, belong the foraminifera, ostracoda, mollusca, and certain vertebrates such as fishes. The highest concentration of these beds of fossils is found in the Miocene shales where the siliceous organisms predominate. In many places thicknesses of 4,000 to 5,000 feet of such shale can be measured. In one section of California there appears to be over 7,000 feet of Miocene shale.

The invariable occurrence of deposits of organic shales in close association with almost all California oil fields has long been recognized. Consequently, it has been logical to assume that in some manner organisms similar to those found in the rocks were the origin of petroleum. Whether the oil as it exists and is produced today is simply a modification of that formed during the life processes of the plants and animals has not yet been proved. Some evidence, however, suggests that the soft parts of these organic forms have contributed to the formation of the oil.

GENERATION OF PETROLEUM FROM ORGANIC SOURCE ROCKS

While, as has been pointed out in the preceding section, the sedimentary rocks locally contain large quantities of organic material from which petroleum may be produced by heating, this material is not necessarily, nor even commonly, buried in the sediments in the form of oil. It is buried in the form of " source material " from which petroleum may be produced under the proper conditions. By what means is this transformation accomplished in nature? This is one of the great unsolved problems of petroleum geology.

A number of theories have been proposed, only a few of which are summarized briefly in this report.

One of the theories of the generation of petroleum is that the oil, or a considerable part of it, is formed from its mother substances relatively soon after these have been buried in the sediments, through the action of bacteria and various chemical reactions associated with that action. This is the so-called biochemical theory. Others have suggested that the action of high pressures, possibly accompanied by local and temporary high temperatures, in connection with earth movements such as faulting may have been the principal cause of the change of part of the organic material into the form of petroleum. A suggestion of a large-scale method by which the source materials may be " cracked " into petroleum is derived from the fact that in the regions in which the rocks have been subjected to high pressures and

high temperatures during the formation of mountains, so that they have been partly metamorphosed, the organic source rocks are found to have lost their volatile constituents, including both the gases and the oils. It is suggested that such partial metamorphism of the source rocks by dynamic forces is capable of generating large quantities of oil. Still another group of scientists holds that much of the petroleum originally was deposited with the sediments in the form of free oil, disseminated in minute globules which were later squeezed out of the source rocks and concentrated into commercial pools. Certain evidence from California seems to support this view.

Study of some of the organic plants and animals composing the California organic shales has indicated that these plants and animals contain minute globules of a fatty material. Experiments have determined that a part at least of this fatty material may be hydrocarbons or a substance easily convertible into a hydrocarbon such as petroleum oil. That a hydrocarbon oil may be obtained by cooking a mass of these minute plants and animals has been fairly well established. Evidence of this nature, although it may not be entirely conclusive, leaves but little to the imagination as to the probable origin of petroleum in California.

It is entirely possible, and even probable, that, while no one of the theories sketched above completely explains the generation of oil from its source rocks, each of them is a true explanation which is applicable in certain instances. In various localities and under various conditions oil may have been formed in all of the ways outlined above.

MIGRATION AND ACCUMULATION OF PETROLEUM

After the oil has been generated from its source rocks, there remains the necessity of its migration to and accumulation in suitable reservoirs before a commercial pool is possible.

How the oil migrates through the rocks to its reservoirs and why it accumulates in certain places and not in others

are interesting and important problems, the second of which is much better understood than the first.

Since the shales and the limestones (or, rather, the calcareous oozes which later become limestones) are the principal rocks in which the organic débris later to be converted into oil is buried, and since both of these rocks are relatively impervious, the problem of the early migration of the oil out of these impervious beds into more porous ones is not without difficulties. If the oil has been buried with the sediments in the form of free oil, as some contend, or if it is formed by biochemical agencies soon after the sediments have been laid down, it seems probable that the oil is squeezed out of the shales and limestones, along with the large quantities of water which they contain, as the rocks are compacted under the weight of other sediments laid down on top of them. On being squeezed out of the shales or oozes, the oil is supposed to find its way into beds of sandstone or other porous rock in which further migration is relatively easy. If the soil is not formed until long after the source rocks have been buried, as under the theory of its formation during mountain building, it is probable that it is able to find its way out of the shales along fissures and joints produced by the same forces which build the mountains.

After the oil has entered the more porous rocks it is free to migrate more or less widely. It may travel either alone or with water through pores of sandstones or through larger openings such as systems of fissures or the porous and cavernous beds of limestone commonly found beneath buried unconformities where the rocks have once been rendered cavernous by exposure to the weather and later buried.

In all of its underground travels, oil is constantly under the influence of its buoyancy in relation to water, which causes the oil to seek the highest possible points along its course. Wherever opportunity offers, the oil works its way upward from one bed to another; it tends to gather along the roof of its porous carrier bed, and wherever this bed has

an impervious cap and is arched or domed in such a way as to form a closed trap the oil gathers into a "pool," which may be of commercial size. It is this principle which furnishes one of the most useful guides for the geologist in his search for hidden accumulations of oil.

RESERVOIRS OF OIL AND GAS

Reservoirs yielding oil and gas are generally found in sedimentary rocks. In a few recorded instances oil has been found in igneous and crystalline rocks, though generally not in sufficient amounts to be important commercially. Most of the oil produced in the United States is found in porous, sandy strata varying in texture from fine-grained sandstone to conglomerate. These rocks are termed "sands." Considerable oil is also found in limestone, and a small amount is produced from fissures in shale.

The oil sands of California are loosely cemented sandstones and soft unconsolidated sands consisting of irregular and angular shaped sand grains. In Oklahoma the greater part of the oil is produced from consolidated sandstones which vary in texture from soft and friable, to hard and firm. In the Texas Panhandle oil fields much production comes from granite wash—a conglomerate composed of granite fragments that have been eroded from granite ridges and deposited along their slopes—and from overlying dolomite. Most of the oil produced in Pennsylvania and West Virginia comes from hard, fine-grained sandstones and compact conglomerates.

Oil is produced from limestone and dolomite in the fields in west Texas and in the Lima field in northwestern Ohio, and the larger part of the oil produced in the Texas Panhandle comes from limestone or dolomite. The Luling field in Texas and the Irvine field in Kentucky, as well as some of the fields in northern Louisiana, also produce their oil from limestones.

Although most of the oil produced in the Salt Creek field, Wyo., comes from sands, some oil has been produced in

commercial quantities from crevices in the shale strata that lie above the First Wall Creek sand. Oil is also produced from fissured shale in a few fields in California, at Florence, Colo., and in several small fields in Pennsylvania.

Core samples have shown that most oil fields in California, unlike those of the Mid-Continent and Eastern districts, comprise a series of oil sands, sandy shales that may bear oil, and shales. These strata may have a thickness of a few feet to as much as 2,000 or 3,000 feet. Frequently, wells in the California fields drain a zone several hundred or more feet in thickness.

Not only are the productive zones of varying thickness, but their porosities differ and sometimes are as high as almost 40 per cent. In contrast to this, the porosity of some of the dense, fine-grained sandstones from which oil is produced in Pennsylvania is as low as 7.5 per cent.

Each producing sand in the average deep well in California may have a different texture, and the degree of saturation is seldom the same in any two producing horizons. Formation pressures are not the same in the various producing zones; because of the great difference in the depth of the individual sands in different wells, caused by the pronounced dip of the formations, each sand may even have different pressures in various parts of the same field.

The characteristics of the oil and gas found in the various producing sands in a California well and the relative proportions of gas and oil generally differ. Even the gravity of the oil in the upper and lower sands in single wells shows a considerable range. In California, also, lenticular sands and shales are common, and although some of these might be isolated from water, nearly all the oil sands are flanked by edge water.

In general, oil reservoirs may be divided into three types, which differ as to nature and origin and which have important bearing on the manner in which the oil is yielded to wells drilled into them.

Probably the most common type of reservoir, which may be called the *pore* type, is that in which the oil is contained in minute pores in the reservoir rock. Sandstone or sand is the most common reservoir of the pore type. Limestone and dolomite reservoirs are of the pore type in some instances.

Other reservoirs are of the *cavernous* type, in which the porosity is in the form of larger or smaller caverns or solution channels such as are very commonly formed in soluble rocks like limestone, dolomite, or salt. Limestones which have been exposed to erosion and later buried have produced many oil reservoirs of the cavernous type. The solution channels may vary from minute channels honeycombing the rock to caverns large enough to permit drilling tools to drop several feet when they are struck.

The third or *fissure* type of reservoir is that in which the porosity is due to open fissures in what may otherwise be impervious rocks, such as shale or impervious limestone.

In their effect on the behavior of a well drilled into them, the reservoirs of the cavernous type and those of the fissure type may be grouped together, because in both the openings are relatively large, and the flow of oil through them is relatively free and is not subjected to serious interference by the action of capillarity.

STATUS OF OIL IN RESERVOIR ROCKS

Oil exists in its undisturbed reservoir rocks under a pressure which generally corresponds rather closely with that of a column of water of a height equal to the depth of the reservoir below the surface. This pressure is undoubtedly hydrostatic. In some instances the pressure may be more or less than hydrostatic, but these instances are believed to be due to special conditions.

The relations of oil, gas, and water in various reservoirs differ widely and have the greatest influence on the manner in which the oil is produced when the reservoirs are tapped. In some reservoirs there is little gas and the oil is backed

up by water in hydrostatic connection with it, so that as the oil is produced at the wells the water follows up in its place. Such wells yield their oil by steady flow, which may continue at a fairly uniform rate for a considerable time, or even until most of the oil has been produced. The water acts as a natural water drive, and is thought, in many cases, to cause a high percentage extraction of the oil.

In some reservoirs the oil pool is not backed by water in hydrostatic connection with it, so that only the expansive force of the gas associated with or dissolved in the oil is available to force it out to the well. The recovery of oil by natural means from such a reservoir depends mainly upon the action of the expanding gas in driving oil to the well and in carrying it to the well in the form of films surrounding the gas bubbles. When the gas energy has been exhausted, the oil still remaining in the sand, which must necessarily be a large proportion of the original amount, remains irrecoverable except by other than natural means. When a reservoir of this type at great depth and under correspondingly great pressure is first tapped, the effect of the expanding gas is almost like that of an explosion, and spectacular gusher wells are the result.

In some instances the oil in the reservoirs is backed by water in hydrostatic connection with it and also contains free and dissolved gas under high pressure. In such cases the results of tapping the reservoir combine the spectacular gusher production of the gas expansion type with the sustained later production characteristic of hydrostatic water drive.

The type of reservoir also exerts great and characteristic effects on the behavior of wells tapping it. Reservoirs of the pore type yield wells of relatively moderate initial production, gradual decline, and long life—results of the difficulty of movement of the oil through the minute pores in which it is held in the reservoir rock. Reservoirs of the cavernous type yield wells of high initial production and characteristically rapid decline. Since the caverns or solu-

tion channels in which the oil occurs are large enough to permit free movement, the oil is produced rapidly and exhausted rapidly. Interference of wells is common; early wells in the field have enormous advantages over later ones, and spotty distribution of large and small wells is also common. Shooting of small wells has been known to result in large production caused by breaking of the shot into channels not tapped by the well bore.

Fields producing from limestone or dolomite, from salt-dome cap rock, and from fissures in shale commonly show the characteristics outlined above.

In planning methods of operation to secure the greatest percentage of oil extraction from a reservoir and methods of recovering oil from depleted fields, the nature of the reservoir—whether of the pore, cavernous, or fissure type—and the nature of the force driving the oil to the wells—whether gas expansion alone, water drive alone, or a combination of the two—are vitally important considerations. Methods which are effective with one type of reservoir or of driving agent are likely to be entirely inadequate under other reservoir conditions.

CAPACITY OF SANDS FOR STORING OIL

Porosity is the ratio of effective pore space to the volume of sand and therefore usually represents the capacity of a sand for storing oil. According to Melcher[3] of the U. S. Geological Survey, "the pore space can be divided into two kinds, the total pore space and the effective pore space. The total pore space is the total interstitial space and includes not only the communicating pores, but any isolated pores that may exist. The effective pore space, on the other hand, is relative, depending on such factors as the constitution of the liquid, the size of the pores, the material of the rock, temperature, pressure, and other conditions."

[3] Melcher, A. F., Determination of Pore Space of Oil and Gas Sands: Trans. A. I. M. E., vol. 65, p. 469, 1921.

Production men are interested mainly in the effective pore space of reservoir rocks, since oil trapped in isolated pores can rarely, if ever, be recovered.

Oil sand composed of spherical grains of uniform size will have more pore space between grains than one composed of grains of many sizes and irregular shapes. Where the grains are not of uniform size, the smaller grains may fill the interstices between the larger grains and reduce the porosity. It is a mistake to assume that because a sand has high porosity it will yield its oil readily and ultimate recovery will be high. The size and arrangement of the pore spaces have a marked influence on the rate of movement of oil through the sand. Oil will flow more readily in sands with large intercommunicating pore spaces than in so-called " tight sands " where the pore spaces may be so small that adhesion and capillary attraction retard the movement of the oil, even though the porosity may be greater. If the expulsive forces in a low-porosity sand are high and the sand is of coarse grain with the pore spaces in communication, ultimate production may be relatively higher than from a high-porosity sand. On the other hand, when the oil is of low gravity and high viscosity, relatively higher recoveries will be had from sands of high porosity than from those in which the volume of the pore space is less.

The oil sands that are being developed in the Salt Creek field, Wyo., are locally known as the First, Second, and Third Wall Creek sands.[4] Of these three, the Second sand is by far the most important. Other productive sources of oil are the crevices in the shales above and below the sands, and a fourth sand, the Lakota.[4a] In the center of the field the First Wall Creek sand is reached at a depth of 900 to 1,000 feet, the Second sand at a depth of 1,300 to 1,400 feet,

[4] Estabrook, Edward L., and Rader, Clarence M., History of Production of Salt Creek Oil Field, Wyoming: A. I. M. E., Petroleum Development and Technology in 1925, p. 199.

[4a] Since this report by Estabrook and Rader was written, it has been determined that the Third Wall Creek sand is of no consequence. The Lakota is the next most important producing horizon below the Second Wall Creek sand.

and the top of the Third sand is at a depth of about 1,520 to 1,650 feet. The thickness of the First sand varies from 120 to 140 feet and that of the Second sand from 60 to 70 feet.

Microscopic examinations show that the sands are composed almost entirely of quartz grains which are in general angular to subround, and that the cementing material is made up principally of sassurite composed of chlorite, kaolin, sericite, secondary quartz, and calcite. Although the average specific gravity of the sand material in both

Table 1.—Typical Screen Analysis of Samples of Sand from the First and Second Wall Creek Sands, Salt Creek Field, Wyo.

	Opening		Mesh	Per cent	
	Inches	M. M.		First sand	Second sand
Retained on	0.034	0.864	20	0.0	0.2
Retained on	.0164	.417	35	.0	2.6
Retained on	.0116	.295	48	.0	4.1
Retained on	.0082	.208	65	2.5	28.6
Retained on	.0058	.147	100	23.7	37.3
Retained on	.0042	.107	140	36.4	13.3
Retained on	.0029	.074	200	16.8	3.6
Retained on	.0021	.053	270	8.2	2.6
Through	.0021	.053	270	12.4	7.7
Total	....	....	....	100.0	100.0

formations is 2.3 (water = 1), the average porosity of the two sands differs, being 21 per cent in the First Wall Creek sand and 24 per cent in the Second. Table I shows the difference in fineness of the sand material composing the First and Second sands.

The screen analysis shows that the Second sand was composed of relatively coarse grains. Only 26.2 per cent of the First sand was coarser than 100 mesh, whereas 72.8 per cent of the Second sand was retained on the 100-mesh screen. The lower porosity of the First sand, as compared with the Second sand, can be accounted for by the fact that it was

composed of a greater percentage of fine grains, which filled the pore spaces between the large grains.

Oil sands consist usually of strata of different textures and characters, separated frequently by more or less impervious layers, which may have a thickness of a few inches or many feet. The degree of saturation is seldom the same in any two strata or even in the same strata throughout the area of the field. Variations in texture of oil sands vertically are frequently disclosed when drilling new wells or deepening old ones, and it is found that a few inches in depth make an otherwise small well yield large production. Variations in texture may also occur laterally, sometimes within short distances. Every oil man knows of one or more instances where a well in one location was a good producer, while at the next location little or no production was obtained because the sand was "too tight." An outstanding example of a lateral variation in sand texture is reported by Kirwin and Schwarzenbek.[5] Two wells, 120 feet apart, were drilled into the Deaner sand in Oklahoma to the same stratigraphic depth (52 feet below the top of the sand). The production of the first of these wells was 835 barrels of oil during the first 24 hours, and from the second was only about 10 barrels during the same period of time. The foreman on the property said that the sand in the second well "drilled hard" and although the hardness of the sand in the first well was not reported, it is evident from the production records that there was a pronounced change in the texture of the sand between the two wells.

The Bradford sand in northern Pennsylvania and western New York is commonly supposed to be uniform in texture throughout, but even in this relatively uniform sand, important variations in texture have been noticed.

[5] Kirwin, M. J., and Schwarzenbek, F. X., Petroleum Engineering in the Deaner Oil Field, Okfuskee County, Oklahoma: Bureau of Mines, State of Oklahoma, and the Bartlesville Chamber of Commerce, p. 35, 1921. Obtained from Bartlesville (Okla.) Chamber of Commerce.

MOVEMENT OF GAS AND OIL THROUGH RESERVOIR ROCKS

A reservoir of porous formations containing oil and gas has definite dimensions and is charged with a given amount of oil and gas under a certain pressure before equilibrium within the reservoir is disturbed either by natural causes or drilling. No appreciable amounts of oil and gas are added to a reservoir by natural means during the productive life of a field, nor is there an increase in the original reservoir pressure due to natural causes.

In their original state, in an undrilled or virgin oil field, the several hydrocarbons that comprise natural gas under surface conditions of temperature and pressure may be considered as existing in four separate phases: (1) Dissolved gas in the oil, (2) free gas mingled in the pore spaces with the oil, or collected above it in structurally high parts of the reservoir formation, (3) gas in the liquid phase, and (4) adsorbed gas.

Since the reservoir pressure in many oil fields is well above the critical pressure (see p. 240) of some of the constituents of natural gas, it is certain that some hydrocarbons that are gases at atmospheric pressure and temperature are liquids in the reservoir. Natural gas is a mixture of methane and heavier hydrocarbons, some of which liquefy at the pressures found in oil structures. Above their critical temperature, however, gases cannot be liquefied by pressure. Methane, for instance, could not be liquefied by any pressure in a well because the temperature in wells is never as low as its critical temperature, and ethane can be liquefied only where the temperature is below 95° F. All other gases in natural gas may easily exist as liquids in reservoir formations.

Table 2 gives the critical temperatures and pressures of a few of the methane series of hydrocarbons found in petroleum.

The principal source of inherent energy contained in an oil reservoir during its early life is the expansive force of the gas associated with the oil. Oil men agree, and laboratory and field experiments have definitely established the fact, that most oil fields have become depleted not on account of the exhaustion of the oil in the reservoir, but because of the depletion of the gas pressure. Laboratory experiments,

TABLE 2.—CRITICAL TEMPERATURES AND PRESSURES OF VARIOUS HYDROCARBON GASES *

	Critical temperatures, °F.	Critical pressures, pounds per square inch
Methane	—139.9	736.5
Ethane	95.0	665.8
Propane	206.6	662.8
Butane	307.4	522.0
Pentane	387.0	486.6
Hexane	454.1	441.9
Heptane	512.3	394.8
Octane	565.5	371.2

* Day, David T., Handbook of the Petroleum Industry: Vol. 1, John Wiley & Sons, Inc., 1922, p. 730.

followed by experiments in various oil fields and especially in areas where rejuvenation methods are being applied, substantiate the fact that ordinarily the recovery of oil from sands through the propulsive force of the gas dissolved in the oil has been on the average only 15 to 20 per cent of the oil originally contained in the sand. Cores from depleted oil sands in the Bradford field in Pennsylvania showed that at least 64 per cent of the original oil was retained in the sand after ordinary pumping methods had been followed by a water drive. Data on the Péchelbronn mine in Alsace, France, indicate that only 16.7 per cent of

the original oil was secured by production through oil wells by ordinary pumping methods.

Experienced oil men and engineers concur that modern improved production methods, as for example the holding of back pressure on flowing and pumping wells, and the scientific production of oil result in the recovery of a greater percentage of oil than was possible by former less efficient methods. Certain controlled experiments [6] on oil recovery conducted by engineers of the Bureau of Mines show 24 to 33 per cent recovery of oil from sand for 500 pounds initial gas pressure and a recovery varying from 30 to 43 per cent when the initial gas pressure was 1,000 pounds per square inch. The results of these experiments " indicate that the percentage recoveries of oil originally occurring in sands at different initial gas pressures may be somewhat higher than has been supposed by some engineers."

It is recognized that water associated with oil may materially aid in the drainage of oil from reservoir sands. Water is especially active as a propulsive force when the pore spaces in the sand are of capillary size since water has about three times as much force of surface tension as oil. Edge water, motivated by hydrostatic pressure, acts as a natural water drive in some fields. The effect of edge water is especially noticeable in certain fields where the gas pressure has been dissipated and the drainage of oil to wells ahead of the water " wave " continues at a rate which makes production profitable.

Edge water, if allowed to encroach too rapidly, may bypass the less permeable lenses filled with oil. However, where its rate of encroachment is controlled by back pressure or other production methods, the effect of edge water may be advantageous in flushing the sands and maintaining a pressure on the oil in the sands.

[6] Mills, R. Van A., Chalmers, Joseph, and Desmond, D. D., Oil Recovery Investigations of the Petroleum Experiment Station of the U. S. Bureau of Mines: A. I. M. E. Technical Paper 144, p. 26, 1926.

Top water, or bottom water, in oil reservoirs is usually considered detrimental to the efficient recovery of oil from reservoir sands. The effect of such waters in driving oil away from wells and entrapping it in the tighter and less permeable sands is due to the lower viscosity and greater surface tension of the water and to the selective permeability of the sands which results in greater freedom of movement of water than oil. It is believed that top and bottom waters enter the channels already open or partially depleted of oil and isolate the less permeable sands, sealing quantities of oil in these lenses and forever preventing its recovery.

Once a sand or portion of a sand becomes flooded, it is desirable to exclude it from among those sands being produced, since the greater mobility of the water will soon enable it to drown out the oil in other sands unless they are under much higher pressure than the water.

The force of gravity is a factor of some importance in the recovery of oil in fields where the producing strata are thick or steeply inclined, but at best it is a comparatively slow-acting force. During the early life of fields in the United States it is improbable that gravitation is of much importance as a factor in the drainage of oil from sands, because the dips of most of the oil-producing formations are relatively low and the sands are irregular in texture and bedding.

Gas pressure, water pressure, and gravity are usually present in the same reservoir. Except for a minority of areas, such as the Gulf Coast, West Texas, and Mexico, the Augusta and Elbing fields in Kansas, and a few fields in the Rocky Mountain district, the evidence is convincing that gas pressure is the predominating force that drives the oil toward the wells. At the Mexia, Powell, and to some extent at the Seal Beach (Calif.) fields, gas appears to be the predominant expellant at first and is followed later by water pressure. The initial production peak in those fields, however, was due directly to the original gas pressure.

As there is no appreciable encroachment of water surrounding the oil in the Salt Creek field it has been definitely proved that the oil from the Second Wall Creek sand is produced by the expulsive force of gas, even though the closed-in pressure—which now approximates 30 pounds per square inch—and the very low fluid levels in the wells indicate that most of the gas has been dissipated. There has been a certain amount of water encroachment in the First Wall Creek sand, but even though the encroaching water may have replaced the oil, a great deal of gas still accompanies the First sand production. This fact indicates conclusively that oil from this formation is produced by the force of gas to a greater extent than by the force of the incoming water.

In the Rocky Mountain fields generally, as well as in other sands in the Salt Creek field, large amounts of gas accompany the production of oil. In some fields there is no encroachment of water and in others the water encroachment has not replaced in the sand a volume of water equivalent to the amount of oil extracted. This condition indicates that gas in those fields is the most important expulsive agent. There are other Rocky Mountain fields which are believed to be producing as a result of hydrostatic pressure in addition to gas pressure, but in most of the fields, the gas pressure is considered to be the chief force that drives the oil to the wells.

Wells in the Lance Creek field, Wyo., produced up to March 1, 1927, a total of 3,159,220 barrels of light oil and 40,000,000,000 cubic feet of gas. Depletion of gas from the Dakota sands of the field represents about 67.7 per cent of the total mechanical energy originally contained in the formation gas. This quantity of oil and gas passed across a line of escape less than 90 feet in length, representing the sum of the circumferences of 43 wells, while edge water, retarded by viscosity and surface tension, advancing from all sides across a line 64,000 feet long, representing the periphery of the Dakota sand field, has been unable to follow

fast enough to fill the space vacated by the oil and gas. It is true that edge water has advanced locally, far up the structure in the Dakota sands, with obvious damage to the oil belt, but it is quite evident in this field that gas is still the principal agent that drives the oil to the wells. These data on Lance Creek wells show further that gas and oil travel in sands with greater facility than does the water that follows them.

In the majority of oil fields in the United States, oil production declines with the decline in underground gas pressure. Less gas is produced as the wells become older, and finally oil production becomes so small that the wells are abandoned and the oil reservoir is said to be exhausted. The fact that much oil remains underground has been proved repeatedly in those fields where gas or, as in certain fields in Pennsylvania, water from external sources has been introduced into the " exhausted " reservoir sands and has increased production from the wells.

The amount of energy available for doing work in driving oil from sands to wells depends on the original reservoir pressure and gas volume, and the ultimate recovery of oil is influenced greatly by the original ratio of gas to oil in the reservoir.

The curves on Figures 1, 2, and 3 show monthly oil and gas production and corresponding gas-oil ratios for three major fields in California. They afford definite evidence of the importance of gas in oil production. It may be noted that the period of maximum oil production coincided with the period of maximum gas production. This period was likewise that of greatest reservoir pressure. Of further interest is the fact that the peak of gas production followed the peak of oil production by about two to five months. This, and the fact that, for a period, subsequent gas production declined faster than oil production, indicates that gas pressure is the chief cause of oil movement in the drainage of reservoir sands.

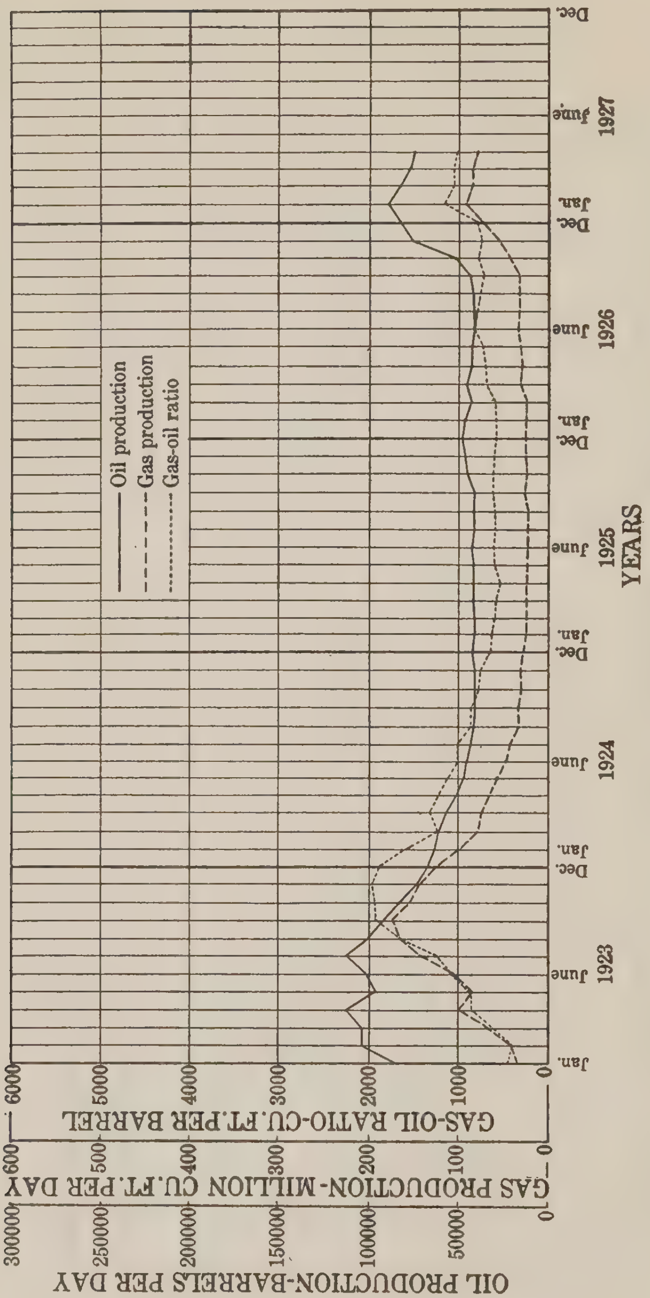

FIGURE 1.—Production graph showing history of total oil and gas production, and corresponding gas-oil ratio. Huntington Beach field, Calif.

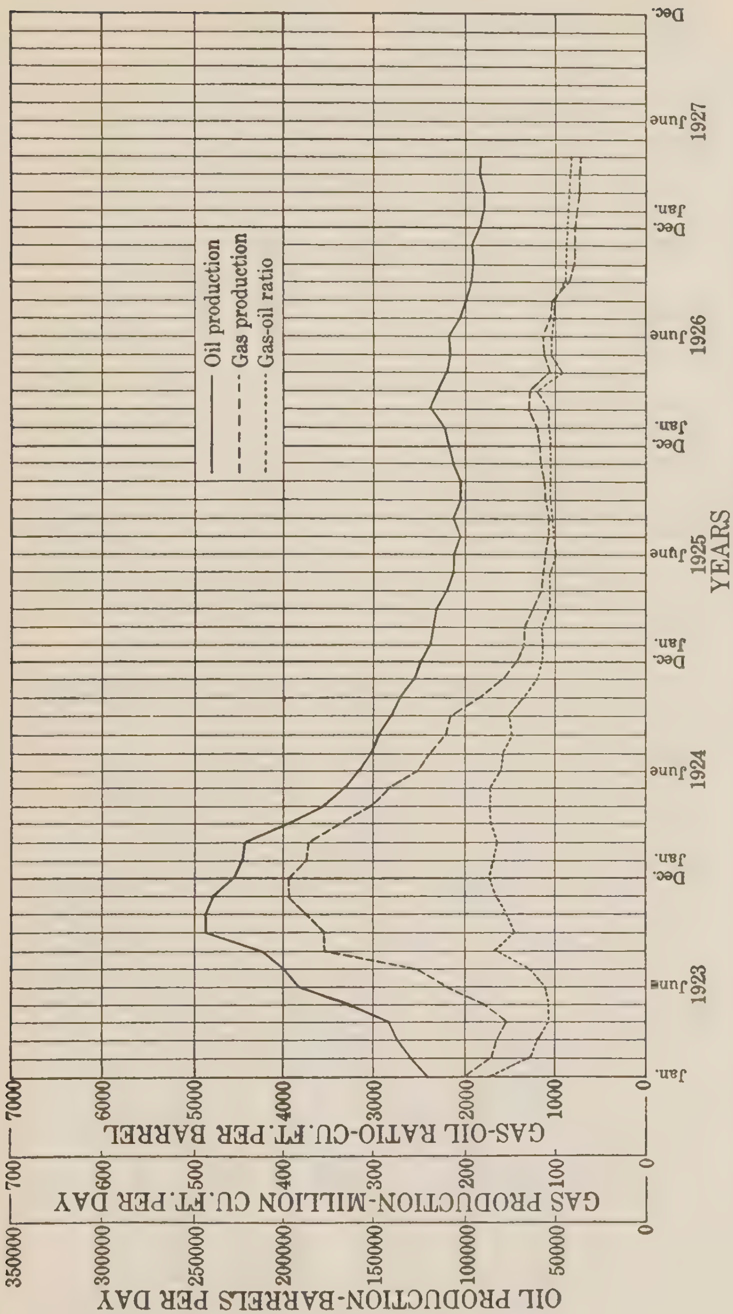

FIGURE 2.—Production graph showing history of total oil and gas production, and corresponding gas-oil ratio. Long Beach field, Calif.

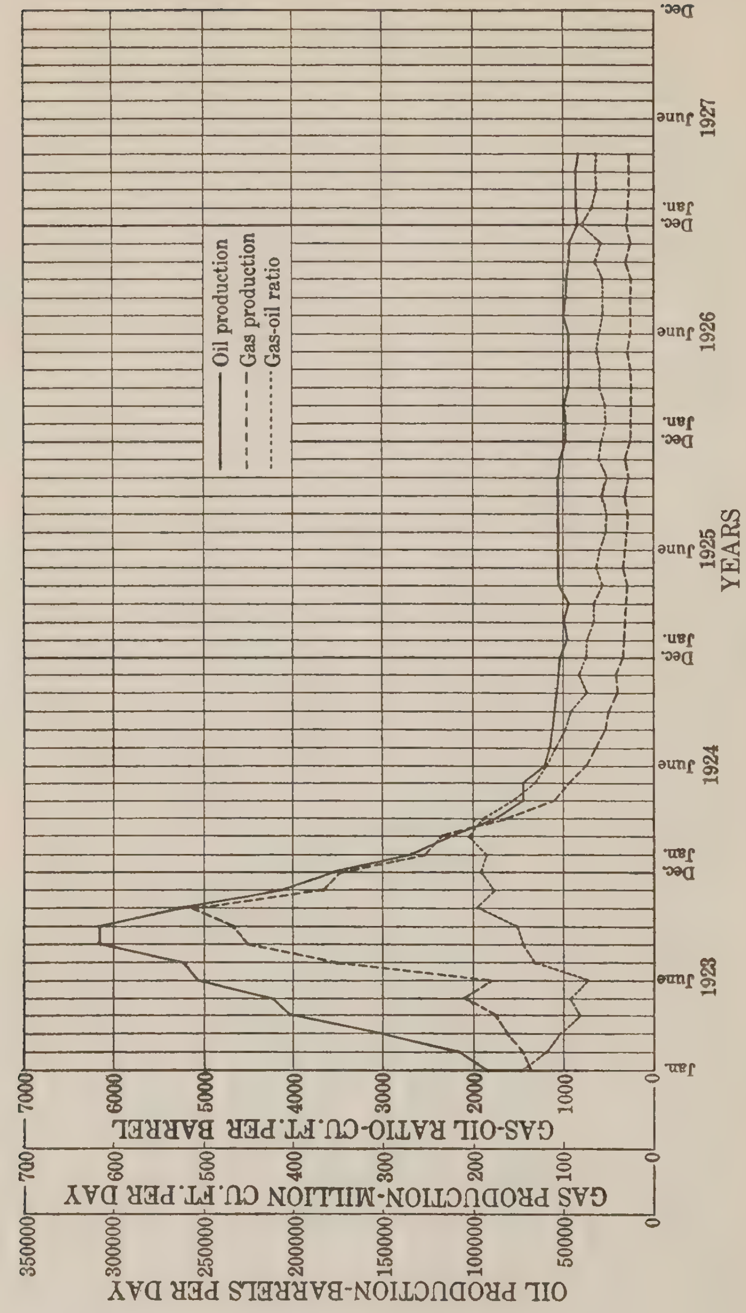

FIGURE 3.—Production graph showing history of total oil and gas production, and corresponding gas-oil ratio. Santa Fe Springs field, Calif.

Gas-oil ratios increased during the period of flush production, then declined, and after one or two years began to take an upward trend again. Gas-oil ratios of flowing wells increase usually until some point a few months prior to the end of their flowing life and then decline because of changes in producing methods. The period of declining gas-oil ratios in the average well is usually short; during the remaining life of the well the gas-oil ratios increase, except possibly during short periods when changes in producing methods temporarily arrest the rate of increase or, in some cases, cause a temporary decline. However, it is accepted generally that gas-oil ratios increase with declining production when consideration is given to the life of the well as a whole, unless the well is affected by hydrostatic pressure. It may therefore be expected that gas-oil ratios of entire fields will increase gradually as they get older and more channels are opened in the reservoir sands through which gas escapes without utilizing all of its energy in moving oil to the wells.

Available records show that the gas-oil ratios from the Second Wall Creek sand in the Salt Creek field, Wyo., increased from approximately 650 cubic feet per barrel in January, 1922, to 2,950 cubic feet per barrel in July, 1925, when only 7 per cent of the wells were still flowing. By December, 1925, the gas-oil ratio dropped to 1,780 cubic feet per barrel. The field was then in the pumping stage and only one-half of 1 per cent of the Second Sand wells were flowing. Between January, 1922, and July, 1925, the closed-in pressure of the Second Sand decreased from about 500 pounds to 85 pounds per square inch, and the initial boiling point of the Second Sand oil increased from 100° F., in 1922, to 116° F., in 1924, and 145° F., in July, 1926.

The Huntington Beach curves, Figure 1, are of further interest in that oil and gas production and gas-oil ratios increased again at a rapid rate in the latter part of 1926 as a result of the development of a new "flush" area—the Huntington Beach Townsite.

The relation between gas-oil ratios and the amount of oil recovered per acre on 24 scattered leases in the Burbank field, Okla., is shown in Table 3. The table is arranged according to the average gas-oil ratios, beginning with the largest and ending with the smallest average ratio. It should be noted that even though there is no consistent increase in the amount of oil recovered per acre for decreasing gas-oil ratios, there nevertheless is some indication that low gas-oil ratios are conducive to higher oil recovery. On 10 leases the average gas-oil ratios were less than 2,000, and on 8 of these 10 leases the amount of oil recovered per acre

TABLE 3.—RECOVERY OF OIL PER ACRE AS RELATED TO GAS-OIL RATIOS ON 24 LEASES IN THE BURBANK FIELD, OKLA.

Example No.	Number of producing wells on lease	Oil recovered per acre, bbls.	Gas-oil ratios, cu. ft. per bbl.			Average thickness of sand, ft.
			Average	Maximum	Minimum	
1..........	14	6,469	13,000	20,000	9,500	49
2*.........	2	601	12,000	21,000	3,500	51
3..........	13	4,097	8,000	10,000	7,000	53
4..........	6	1,636	5,500	7,200	5,000	40
5..........	12	4,272	3,900	4,700	2,700	51
6..........	16	5,050	3,000	10,000	1,500	..
7..........	14	6,510	3,000	3,500	2,700	40
8..........	16	13,468	2,800	3,370	2,350	62
9..........	16	6,461	2,750	3,300	2,500	53
10..........	12	7,973	2,300	2,770	1,650	51
11..........	14	8,913	2,300	2,500	2,100	56
12..........	14	4,692	2.000	3,170	1,230	48
13..........	8	3,417	2,000	2,400	1,000	45
14..........	16	9,728	2,000	2,500	1,700	43
15..........	16	12,038	1,950	2,300	1,850	72
16..........	16	7,668	1,800	2,700	500	46
17..........	16	13,032	1,800	2,400	1,450	..
18..........	16	4,196	1,700	2,200	600	55
19..........	19	17,005	1,600	1,870	1,000	28
20..........	16	16,238	1,600	2,000	1,100	50
21..........	16	12,284	1,500	2,500	500	52
22..........	16	4,501	1,000	2,960	460	..
23..........	8	19,181	600	1,000	300	..
24*.........	2	11,406	600	1,550	150	..

* Edge lease.

was in excess of 7,000 barrels. The average gas-oil ratio on the remaining 14 leases was 2,000 and over, the maximum average ratio being 13,000, and on only 4 of the 14 leases was more than 7,000 barrels of oil recovered per acre. Certainly these figures indicate that gas is an important factor in the production of oil. Furthermore the control of gas-oil ratios so as to produce the oil with the least amount of gas is reflected in increased oil recovery from the reservoir sands.

There is no doubt in the minds of oil men and engineers that the predominant expulsive force that drives oil to wells is the energy stored in the compressed gas absorbed in or associated with the oil. Admitting that natural gas is usually the most important factor in oil recovery, its control in order to cause it to do the most work in driving oil from the sand to the well is of utmost importance; every possible means should be taken to conserve the gas pressure and prevent its dissipation. Certainly the operator should be able to control the efficiency of the work of natural gas to a greater extent and with far greater effect on the economic ultimate recovery of oil from the sand than he can the efficiency of water and gravity.

RESISTANCE TO FLOW OF OIL THROUGH SANDS

As soon as a well is drilled in and oil starts to flow from the sand, the condition in the reservoir undergoes a change. The reduction in pressure permits gas to come out of solution in the form of minute bubbles, and as the pressure is reduced further, the expansion of these bubbles forces part of the oil through the sand to the well. However, the following and other factors tend to retard the movement of oil toward the well: (a) The increasing viscosity resulting when gas comes out of solution in oil, (b) the surface tension of the oil film on gas bubbles, (c) the distortion of these bubbles in passing through the pore space interstices, and (d) adhesion. At any given time during the life of the well,

a certain amount of energy is required to overcome these resistances and cause the oil to flow to the well. The expenditure of original gas in excess of that required results in a reduced ultimate oil recovery, or requires that a proportionally larger amount of energy be supplied, unless replaced by artificial means, to produce maximum ultimate recovery. It is generally agreed by production engineers that the amount of oil recovered from a given reservoir is inversely proportional to the recovery gas-oil ratio. The problem of the operator then is to use efficiently the store of natural-gas energy, making each foot of gas do the maximum amount of work in moving the oil through the formations and to the wells.

The forces resisting the flow of oil toward wells may be divided into two classes—internal and external. Internal resistances are: (a) The result of the viscosity of the oil itself, increased doubtless in some cases by the presence of finely divided shale particles or colloidal silica which often manifest themselves later as emulsifying agents, and (b) the phenomena known as the Jamin effect, wherein the resistance is increased by the surface tension of the oil film around the gas bubble. To force the bubble through an aperture smaller than itself, it must be distorted from a true sphere; such distortion is resisted by the surface tension of the oil film, and work must be done to overcome this resistance.

External resistance to flow is dependent on the character of the sand, its fineness, uniformity, sharpness, clearness of grain faces, and presence or absence of cementing material, all of which affect the shape, size, and smoothness of the channels through which the oil must move. The external resistance varies with the rapidity at which the oil column is moving at some power, other than the first power, of the velocity. The rate of production therefore seriously affects the amount of energy consumed per barrel of oil in overcoming external resistance to flow, and likewise affects the

amount of gas which must be expanded to furnish this energy.

Adhesion of the oil to the walls of the sand channels, when such channels are sufficiently small, gives rise to capillary resistance. The exact magnitude and importance of capillary resistance under ordinary subsurface conditions are difficult even to estimate. That it is a resistance at least worthy of consideration and study is unquestioned. It is believed that capillarity is an important factor in preventing the separation of oil and gas in a porous stratum while that stratum is in a static condition. Furthermore, the sealing of the pore spaces with oil by capillary action may prevent by-passing of the gas when conditions are no longer static but dynamic.

FACTORS AFFECTING CHANGES IN RESISTANCE TO FLOW

The effect of changing underground conditions on the several resistances to flow is worthy of consideration. Changes which, among others, are important are those of pressure, temperature, and rate of flow. Reduction in pressure allows the free gas, if any, to expand, liquefied hydrocarbons to change from the liquid to the vapor state, and by reducing the solubility of gas in the oil causes some of the gas to come out of solution. All of these changes increase the size and number of gas bubbles in the oil; increase the Jamin effect, both by multiplying the number of bubbles and intensifying the surface tension of the oil; and increase the viscosity of the oil through the escape of dissolved gas. Each of these separate effects tends to add to the amount of work necessary to move a barrel of oil a given distance. Therefore, it is safe to state that the higher the average pressure which can be kept effective on the formation, the more readily the oil will move toward the well.

Decrease of underground temperatures, which might result from sudden release of pressure on the sand and the consequent rapid expansion of gas, is commonly accepted

as being relatively unimportant in its effect on resistance to flow. Lowered temperature would result in greater solubility of gas, which would tend to lower the viscosity and surface tension; this effect, however, would be offset by the direct temperature effect on the viscosity and surface tension, both of which are increased at lower temperatures. Certain oils have the viscosity increased greatly by lowered temperatures, and others precipitate waxes or waxlike solids which increase production difficulties greatly. Any change in operating methods that would result in lowered underground temperatures is therefore to be avoided.

Changes in the rate of flow affect the efficiency of production by increasing the energy consumed in overcoming internal and external resistance to movement of oil through the sands. A rate of flow is therefore desired which will balance efficient use of the gas energy against the operator's desire for high productivity of wells.

EFFECT OF DISSOLVED GAS UPON THE VISCOSITY AND SURFACE TENSION OF CRUDE OIL

The rôle that natural gas plays in the production of oil is twofold; first, natural gas in solution in petroleum imparts desirable physical properties to the crude for its efficient migration, and second, the force of expansion of natural gas, as discussed in the section on the movement of gas and oil through reservoir sands, acts as a propellant in moving oil through reservoir sands to the well which is the point of lowest pressure.

From laboratory experiments it is found that gas in solution in crude oil decreases the viscosity and surface tension, thus imparting physical properties to the oil which are conducive to the utilization of less energy in causing it to flow. It is believed that the results found in the laboratory have their application to conditions as they exist in the reservoir sands. A knowledge of the results of these laboratory tests

is essential, therefore, to an understanding of the desirable physical effects that natural gas in solution has on petroleum.

REDUCTION OF VISCOSITY BY DISSOLVED GAS

The amount of gas dissolved in a crude oil is directly proportional to the gas pressure. Beecher and Parkhurst[7] found that by saturating a given crude with natural gas at 500 pounds pressure per square inch and 70° F., the viscosity was decreased 50 per cent. It is therefore within the bounds of reason to assume that at a pressure of 1,800 pounds per square inch, corresponding to a depth of about 4,100 feet, enough gas may be dissolved in the crude in an oil reservoir to reduce the viscosity to that of kerosene.

The rate of change in viscosity of oil on account of gas in solution is dependent upon the amount of gas dissolved and upon the character of the oil and of the gas. A crude oil of high initial viscosity will show an appreciable change with even small amounts of dissolved gas, whereas a crude with a low initial viscosity shows only a small change even when several times as much gas is dissolved.

In the viscosity experiments made by Dow and Calkin[8] on a crude from the Lost Soldier field, Wyo., which had an initial viscosity of 550 seconds Saybolt at 100° F., the viscosity was decreased 18.5 per cent when 11 cubic feet of natural gas per barrel was dissolved in the oil. The viscosity of an Oklahoma crude was decreased approximately 13 per cent when 30 cubic feet of gas was in solution per barrel of oil. Experiments by Beecher and Parkhurst show a decrease of 33 per cent in the viscosity of a 30.2 A. P. I. gravity crude from Oklahoma when 90 cubic feet of gas was in solution per barrel of oil.

[7] Beecher, C. E., and Parkhurst, I. P., Effect of Dissolved Gas upon Viscosity and Surface Tension of Crude Oil: A. I. M. E., Petroleum Development and Technology in 1926, p. 51.

[8] Dow, D. B., and Calkin, L. P., Solubility and Effects of Natural Gas and Air in Crude Oils: Bureau of Mines Reports of Investigations, Serial No. 2732, Feb., 1926.

The viscosity of a crude oil decreases as the temperature increases, and the higher the temperature the less gas will be dissolved in the oil, if other conditions are constant. However, the relative decrease in viscosity is approximately the same for an equal volume of a given gas dissolved in the oil at different temperatures.

REDUCTION OF SURFACE TENSION

Dissolved gas reduces the surface tension of crude oil, and there is a distinct relationship between the percentage of reduction in surface tension and the volume of dissolved gas. Beecher and Parkhurst[9] found that equal volumes of the same gas dissolved in two different crude oils caused the same relative decrease in surface tension.

It is generally known that a large percentage of oil which present production methods fail to remove from reservoir sands is held by capillarity—a measure of surface tension. The surface tension and likewise the capillary force is increased as the gas that is dissolved in the oil escapes. If this increase in surface tension could be prevented during the process of extracting the oil from the sands, a greater volume of oil should be recovered. Waste of gas in production operations, therefore, indicates decreased ultimate recovery.

EFFECT OF VISCOSITY AND SURFACE TENSION ON MOVEMENT OF OIL THROUGH SANDS

The quantity of oil that will flow through the irregular openings in a reservoir sand is inversely proportional to the viscosity of the oil when other conditions remain constant. Reducing the viscosity 50 per cent will double the rate of flow. This assumes, of course, that the flow is viscous rather than turbulent. There is some question among engineers as to whether the flow of oil in reservoir sands is of a viscous or turbulent nature. Apparently there is a

[9] *Op. cit.*

time in the life of many wells when the flow is both viscous and turbulent. During the early life of a well which yields large production as a result of the expulsive force of gas, there is undoubtedly back in the sand away from the well bore a slow migration of oil toward the well. A considerable distance removed from the well bore there is no great pressure gradient, probably not enough to permit the gas to come out of solution. Undoubtedly at this point the oil is flowing as a liquid under viscous flow. There is a point, however, somewhere in the sand where the pressure has been reduced sufficiently to permit the gas to come out of solution. Also there is a point near the well where the rate of flow of oil through the sand is greatest. It is possible to imagine that turbulent flow takes place under such conditions.

At many large producing wells which have merely tapped the oil sands, very large flows of oil migrate into the wells through the pores of the sand in a total area not greater than the area of the casing. Certainly the rate of flow of oil at this point may be great enough to be of a turbulent nature. After the gas pressure has been reduced considerably, the flow of oil to the well bore is very probably viscous—a reasonable supposition in view of the low velocity prevailing in the structure except in the immediate vicinity of the well.

It has been determined experimentally that viscosity is an important factor in determining the friction loss in the flow of oil through sand, and that the density of the fluid is a negligible factor. The reverse would be true if the flow of the oil through the sands were of a turbulent nature.

The flow of oil through sands is considered by some engineers to vary directly as the pressure drops; as the square of the effective diameter of the sand grains; as the 3.3 power of the porosity; and inversely as the viscosity. A thin fluid of low viscosity, such as kerosene, will flow through sands with little resistance as compared to the

resistance of a viscous crude oil. If sufficient gas is dissolved in the viscous oil, however, the viscosity may be reduced almost to that of kerosene. Beecher and Parkhurst[10] estimated that the viscosity of the two oils used in their experiments would be reduced from 40 to 70 per cent when saturated with natural gas at a pressure of 1,000 pounds per square inch.

Surface tension does not affect the rate of flow of oil through sand unless bubbles of gas are present. If gas is present as bubbles, the rate of flow will be increased by a decrease in surface tension. The properties of surface tension and adhesive tension concern the total amount of oil recoverable more than they do the rate of production. The higher the surface tension and adhesive tension the more oil will be retained in the sands when the fields are depleted by present production methods.

EFFICIENT USE OF NATURAL-GAS ENERGY

As has been shown, work is necessary to move oil against the combined effects of frictional resistance of reservoir formation material, viscosity of oil, and gas-bubble resistance. Since the principal source of energy to perform this work is the expansion of the gas that accompanies the oil, the amount of gas produced with a barrel of oil has come to be considered as a measure of the amount of work being done underground; the efficiency of wells and properties, therefore, are being compared on the basis of their gas-oil ratios or quantities of gas produced per barrel of oil. Such a comparison is fair only so long as the reservoir pressure conditions are the same, since the amount of work done varies not simply with the quantity of gas, but as the product of this quantity and the reduction in pressure; or, by the number of times the gas has expanded in passing from the formation pressure to its final pressure where it discharges its load of oil into the casing.

[10] *Op. cit.*

Pressure is as fundamental as volume. Obviously, the force exerted by 1,000 cubic feet of gas under, say, 100 pounds per square inch pressure, is far less than the force exerted by the same quantity of gas under 1,000 pounds per square inch pressure. The fundamental factor is the combination of pressure and volume, which together equal the force exerted by the gas. It is this force that is important. In comparing producing methods at the same well, the volume alone can be used as the index, but comparison of recovery gas-oil ratios between fields or even wells in different zones or areas in the same field can be made only by taking into consideration the differences in reservoir pressures, depths, and other factors that affect the amount of work accomplished by 1 cubic foot of gas.

If the mean effective reservoir pressure of a field could be determined, and this is almost impossible in fields that produce from thick zones because of variations in pressure both vertically and laterally, an expansion ratio factor could be calculated. This factor then could be applied to the gas-oil ratio, and the resulting factor, which might be termed an energy ratio, could be considered a fair measure of relative efficiency for comparison with other energy ratios similarly established for wells in the same or other areas.

The proper utilization of gas energy in a field usually requires a variation of operating methods from well to well to best suit the conditions in the individual wells. The many conditions to be dealt with are rarely alike in different fields or in different wells in the same field. This is illustrated by conditions in the Rainbow Bend field, Kans., where the gas-oil ratio increased progressively from 2,000 cubic feet per barrel on the flanks to 7,000 cubic feet per barrel on the crest of the structure. There was also a variation in the specific gravity of the gas from 0.89 (air = 1) on the flanks to 0.73 on the crest.

The blowing of gas wells in the hope that oil will eventually appear is usually inadvisable. In any event it is waste-

ful of gas energy which is so important in expelling oil from reservoir sands. More often than not, when oil does appear or the well is placed on the pump, the gas pressure has been dissipated to such a degree that oil production is very small. An outstanding example of waste of gas energy occurred at the Cook pool, Shackelford County, Tex., when the gas from two wells was allowed to blow into the air in an effort to convert a dry gas area on top of the structure into an oil-producing area. One well was allowed to blow gas for 34 days and the other for 18 days. The total gas that was blown to the air during the interval between completion of the wells and the time when oil first appeared was estimated at 250,000,000 cubic feet. When oil did appear in these wells, the gas pressure had been dissipated to a point where the wells had to be pumped. Even when pumped the amount of oil lifted from one well amounted to but 10 barrels a day, and only 26 barrels a day was obtained from the other.

Blowing large volumes of gas from wells located on top of structures known to contain oil along their flanks is one of the most flagrant violations of the principles of conservation. Although the conversion of a gas area into an oil-producing area might make operations on one property profitable, the losses in production sustained by the majority of operators in the field because of the loss of energy contained in the willfully wasted gas, are in nearly all instances far greater than the value of the total oil recovered from the area on top of the structure that originally contained only gas under high pressure.

Research carried on by one of the larger oil companies in the Mid-Continent fields showed that the volume production of oil from a sand under the propulsive force of its dissolved gas is a function of the initial gas pressure, and that production increases with pressure. Where gas pressure is chiefly responsible for the flow of oil into wells, and it should be remembered that this is true in the majority of fields, the initial production peak of a well or field is due directly to the high initial gas pressure. Decrease in oil

production follows closely the decline in gas pressure, and when the gas pressure is dissipated, the flow of oil to the wells almost ceases even though a large percentage of the original oil may still remain in the sand.

Since gas volume and pressure are of such importance and so necessary to the economic exhaustion of reservoir sands, every effort should be made to cause the gas to effect the movement of the maximum amount of oil through the sands to the wells. Flowing wells "wide open" sometimes encourages the escape of more gas than the minimum amount required to bring the oil into the well. Operating methods that control the flow of oil and gas from wells conserve gas by allowing only such quantities to flow from the reservoir sands as are required to obtain oil production. All efforts to increase the duty of formation gas, and by so doing increase ultimate oil recovery, should be instigated upon completion of each well when the rates of gas and oil production are generally maximum.

For every well there is a critical differential pressure and a critical velocity induced by this pressure which will result in the most economical rate of flow of oil to the well. The problem for the operator is to control the back pressure on each well so that the gas escaping from the reservoir sands will carry the maximum amount of oil to the well. Experience has shown that it is difficult generally to get operators to hold anywhere near enough back pressure on their wells for maximum utilization of formation gas energy. Unless the gas is used efficiently in moving oil to the well, ultimate oil recovery from the reservoir sands will be reduced proportionally.

From the preceding discussion it is evident that the most efficient method of gas utilization is one where the gas moves with the oil so that the gas-oil ratio approaches as nearly as possible the amount of gas dissolved in the oil at the existing reservoir pressure; also, that the most efficient theoretical differential in pressure would be the one which gives this theoretical low gas-oil ratio.

EFFECT OF WELL SPACING AND RATE OF DEVELOPMENT ON THE EFFICIENT UTILIZATION OF NATURAL GAS

GENERAL CONSIDERATIONS

The efficient utilization of the gas associated with oil in reservoir sands depends somewhat on the distance between wells and on whether the field is drilled up slowly or quickly. The spacing of wells upon an oil property is commonly the result of an attempt to balance economic factors against physical factors and the success of such an attempt depends largely on the accuracy with which the physical factors can be determined and weighted. Some of the important physical factors are the formation pressure; amount of gas associated with the oil; permeability of the sands; depth and thickness of the sands; gravity, temperature, and viscosity of the oil; the spacing and arrangement of wells; the rate and order of drilling; and the position of the wells on the structure, and their relation to the edge-water line.

In its practical aspect, rate of development is governed in most cases by lease and offset requirements and by the demand for oil. From a purely theoretical standpoint, no drilling program can equal in efficiency the simultaneous development of an entire tract, because this procedure gives each well the advantage of the high initial pressure. Although simultaneous development of an oil field is theoretically desirable, it is recognized that such development is impossible. For economic reasons the development of a field requires correlation of information obtained from each well as drilled to determine where to drill the next well, in order to eliminate dry holes. There are other economic reasons why simultaneous development cannot be considered ideal. For example, great floods of oil would be produced as soon as the wells reached the oil zone, and flooding the markets with oil, gas, and gasoline would depress prices and encourage waste. Simultaneous development would also necessitate excessive capital expense for drilling

machinery and equipment for transporting oil and gas from other fields for fuel purposes. Tankage and pipe-line facilities would have to be provided to handle the peak production, which in a relatively short time would decline to the point where only a small part of the original equipment would be necessary. This condition might be obviated to a degree by coöperative agreement having for its purpose the holding back of peak production so that equipment of reasonable capacity would handle the oil produced; but obviously, in many fields, especially the town-lot areas in California, coöperative agreements of this nature are impossible.

Immediate repressuring has been suggested as a substitute for simultaneous development. Immediate initiation of gas injection is possible in many fields and is limited only by the mechanical inability to put gas back into the sands where high formation pressures exist. Although immediate repressuring requires relatively high pressures, the cost of compressing gas to such pressures is not excessive; in fact, the cost of compressing gas from atmospheric pressure to 100 pounds per square inch is approximately two-thirds of the cost of compressing it to 1,000 pounds per square inch. In other words, it is the first 100 pounds in the compression of gas to 1,000 pounds per square inch which is the really expensive pressure.

The use of two gas separators on high-pressure wells is recommended to save compression costs. For the purpose of illustrating the saving in compression costs resulting when two separators are used, assume a well, in which the formation pressure is 710 pounds per square inch, flowing through a flow bean against a back pressure of 280 pounds per square inch. Were it desired to inject this gas back into the formation, the cost of repressuring could be very considerably reduced by using two gas separators. If the oil and gas from the well are allowed to flow into a separator from which the gas is discharged at 280 pounds per square

inch, the cost of compressing this gas for re-injection purposes would be the cost of compressing it from 280 to 710 pounds per square inch. The oil from the high-pressure trap would still contain some gas in solution, perhaps about 50 to 60 cubic feet per barrel of oil, which would be released when the pressure is reduced to atmospheric pressure in the second or low-pressure separator. This gas, of course, would have to be compressed from atmospheric pressure to a pressure of 710 pounds per square inch if it is to be injected back into the formation. The volume of this low-pressure gas, however, is but a small proportion of the total volume of gas coming from the well, so that the cost of compressing it will be but a small part of the total compression cost. Often, too, the gas will be needed for fuel and will not have to be compressed.

If the high-pressure trap is not used and all the gas is allowed to expand to atmospheric pressure, the cost of compressing it back to 710 pounds per square inch will be approximately proportional to the logarithm of 710, which is 2.8. By "double-trapping," the cost of compressing practically the entire gas output from the well, from atmospheric pressure to a pressure of 280 pounds per square inch, will be saved. This cost is approximately proportional to the logarithm of 280, or 2.4. The difference between 2.8 and 2.4 represents the energy which is required to compress the gas from 280 to 710 pounds per square inch, which is only 0.4 or one-seventh of the cost of compressing it all the way from atmospheric pressure to 710 pounds per square inch.

Expressed in monetary values and assuming that the cost of compressing gas from atmospheric pressure to 280 pounds per square inch is 4 cents a thousand cubic feet, the cost of compressing a thousand cubic feet of gas from atmospheric pressure to 710 pounds per square inch is 4⅔ cents. It is evident from these figures that "double-trapping" will save a compression cost of 4 cents per thousand cubic feet, based on energy ratios, and that but two-thirds

of a cent is the approximate cost of compressing 280-pound gas to a pressure of 710 pounds per square inch.

Operators generally are of the opinion that close spacing and rapid drilling make for greater ultimate recoveries of oil and gas from a field. The studies from which this conclusion was drawn, however, were made without giving consideration to gas or air injection methods and back pressure control of wells, which in the opinion of certain production engineers might overbalance the effect of close drilling and simultaneous development. It will be shown subsequently (p. 138) in this report that gas or air injection methods recover oil unobtainable by ordinary producing methods, even where every effort is made to control the production of wells so as to utilize formation gas efficiently. Thus, the problems of development and spacing, complicated as they have been in the past, are now made still more difficult of solution in certain areas because of what can be accomplished by injecting gas or air into reservoir sands to assist in moving oil to the wells.

SPACING OF WELLS

The drainage radius of a well has been defined as the distance from the well to the point where the forces tending to move the oil toward the well are just balanced by the resistance to movement in the sand. Obviously this is not a permanent distance, but changes with the age of the well, being increased by the fall of pressure in the area close to the well and often greatly by the drive of encroaching edge water.

Wells spaced too closely are believed to cause excessive gas by-passing, due to the probable intersection of the partially drained areas of several wells in the upper part of the sands. If it be considered theoretically that a cone of at least partly depleted oil sand exists around each well, spreading further back into the formation as time passes, and that these partly depleted sands allow the passage of

gas toward the area of lower pressure—that is, toward the well—more freely than do the less depleted sands, it might easily follow that if the wells are spaced too closely their cones will intersect early in their lives and opportunity will be afforded for great loss of formation energy through inefficient expansion and by-passing of gas. The greater the pressure the sooner will the cones intersect between wells of a given spacing, because oil and gas will move toward the wells with greater velocity. Drilling wells too closely together would cause the same losses in efficiency as too high a rate of production from a single well—namely, excessive friction losses due to too-rapid movement of fluid through the pore spaces of the sand. High Jamin effect would also result at an earlier stage, due to the more rapid drop in formation pressure and the consequent formation of gas bubbles throughout the sand. Too-close well spacing is seen in its worst phases in the town-lot drilling of certain fields in southern California. Large quantities of gas were wasted both on account of inefficient operating methods and the inability of gas-purchasing companies to handle and dispose of the gas which accompanied the oil.

Wide spacing, on the other hand, makes for slower drainage of the sands; slow drainage, if carried on with proper operating methods, means less energy consumption per barrel of oil produced and therefore greater ultimate production by ordinary methods.

It is impossible to formulate the many variables that enter into the problem of well spacing. If the sand is "tight," the oil heavy and viscous, and the gas pressure low, the wells should be spaced closely. How close this spacing should be is a matter that requires a detailed study of the area under consideration. In some shallow fields the spacing may be as close as 100 feet. On the other hand, to drain a porous sand containing high-gravity oil and plenty of gas, wells are spaced as far apart as 660 feet—one well to 10 acres.

Operators usually are interested mainly in obtaining the greatest possible production in the minimum time and at minimum expense. It is generally agreed that with ordinary production methods, wide spacing makes for maximum ultimate production at a minimum expense for development, but does not do this in the short time in which many operators desire to get return of their investment. For this reason many operators space their wells close together and spend greater sums of money for development work.

It is believed, and many field tests seem to indicate, that in some areas wide spacing and early gas injection will reduce the time that ordinary production methods take to recover the oil when wells are spaced far apart and where formation gas pressure and in some instances gravitational drainage are depended upon entirely to bring the oil to the wells. Gas injection not only shortens the time of realization of maximum recovery, but all data obtained so far indicate that even more oil will ultimately be recovered from the sands than present production methods recover. If it can be proved, and it appears that it soon will be, that wide spacing and gas injection recover more oil at a lower cost per barrel than close spacing and ordinary production methods, operators in favorably situated areas should plan their development program with subsequent gas injection in mind.

LOCATION OF WELLS ON THE STRUCTURE

If the property under consideration occupies an entire structure and the wells planned would have considerable differences in structural elevation, it is generally believed that it would be advisable to drill the edges of the structure first and defer the drilling of the higher parts of the structure where the relative quantity of gas to oil is greater. After the edge walls have for some time had the advantage of the full pressure of the formation gas, the high parts of the structure could be drilled.

Operators on the Wellington anticline, Colo., found the gas-oil ratios more difficult to control in wells high on the structure than in wells lower on the structure; they discovered that the structurally higher wells had the higher gas-oil ratios later in their flowing life. Similar observations have been made in California.

That a gas area is associated with the oil area in the structurally high parts of the Wellington anticline in Colorado was evidenced when the discovery well came in as a gas producer and by open flow measured 82,000,000 cubic feet of gas daily. Later a second well in the gas area gaged 67,000,000 cubic feet of gas per day and blew gas for 35 days before spraying oil. It has not been definitely proved that the gas area has any effect on the oil area, but regardless of such effect the policy of the operators from the initial period of production has been to shut in the gas wells on top of the structure with the idea of utilizing to the fullest extent the natural energy of the high-pressure gas to produce the oil. The effect of this policy has not been as noticeable as might be expected; in fact, a well located but 1,000 feet from the gas area only flowed eight days and since that time has been a pumper with a gas-oil ratio averaging but 400 cubic feet per barrel of oil. This might indicate that the gas is in a separate sand altogether or that the oil sands are lenticular or faulted.

Those persons familiar with the underground conditions in the Wellington anticline believe that the low porosity of the sand is a factor controlling the effect of the gas area on the oil area. There is also some question as to the relation of the gas area to the oil area. Regardless of these uncertainties, however, operators are working on the theory that they have everything to gain and nothing to lose by adhering to the practice of shutting-in structurally high gas wells, and that by doing so they will recover more oil ultimately from the Wellington anticline. Experience elsewhere has proved the correctness of such operating practice, and the operators are to be commended on adopting a

policy that unquestionably will yield greater ultimate recovery of oil from the reservoir sands.

Data gathered from approximately 100 Second Wall Creek sand wells in the Salt Creek field, Wyo., show that wells located low on the structure had lower gas-oil ratios than those located at structurally higher elevations. Undoubtedly this fact is due to the tendency of the gas to segregate from the oil and migrate towards the top of the structure. That such segregation occurred was definitely proved when the field had declined to the pumping stage and wells on top of the structure began to produce increased quantities of gas. There was no evidence of any segregation of gas from the oil and its migration to structurally higher points during the early life of the field.

A curve prepared from data pertaining to oil and gas production and to the height of the producing horizon above sea level in the 100 Salt Creek wells, mentioned in the preceding paragraph, showed that where the sand is structurally 2,300 feet above sea level, the wells produced an average of 900 cubic feet of gas per barrel of oil. Those wells in which the producing sand was located 3,500 feet above sea level yielded an average gas-oil ratio of 4,000 cubic feet per barrel. The curve indicated an increase in gas-oil ratio of 500 cubic feet per barrel for every structural rise of 200 feet.

The theory has been advanced that wells should be more widely spaced on top of the structure than on the flanks, because of the selective migration or segregation of the oil and gas in the formation; this segregation is thought to result in the movement of gas up the dip while some of the oil which originally accompanied the gas moves eventually down dip to the flank wells. No conclusive evidence of such action is at hand, but this idea is worthy of mention and future study.

RATE OF DEVELOPMENT

Theoretically, the largest ultimate recovery of oil from reservoir sands is obtained when a field or tract is drilled up quickly. It was intimated also in light of present developments that recovery efficiency might be the same and even greater by slower drilling followed by gas injection. Because gas-injection methods have only recently been applied to any considerable extent and since sufficient time has not elapsed to obtain complete data for comparing the relative merits of slow drilling and gas injection versus fast drilling and ordinary recovery methods, the preponderance of available data naturally favors the ordinary method. It is obvious, however, that although close well spacing and rapid drilling have certain advantages, such a program at times and in certain areas has unfavorable economic factors; the results of such a program are:

1. Increased development and operating costs:
    (a) At wells,
    (b) For storage,
    (c) For transportation.
2. Waste of gas caused by flooding markets and impracticability of storing gas on a comparatively large scale.
3. Depression of price of oil and gasoline caused by overproduction.

An outstanding example of the unfavorable economic results of close spacing and rapid drilling is provided by the town-lot fields in California. Regardless of whether or not ultimate production from these fields will be greater because of fast drilling and close well spacing, the fact remains that large volumes of gas were wasted during the flush production period, gas lines and compressor stations were constructed to handle volumes of gas that were not to be had when construction of these facilities was completed a few months later, tankage was constructed at high cost to store the flush production, and due to overproduction of oil and gasoline the prices of these products decreased so

that the net profits to the producer hardly justified capital expenditures. Fortunately, town-lot development extends to only a few fields, and more orderly drilling predominates in most of the oil fields in the United States.

When reading the following paragraphs on the development of certain fields in Oklahoma and Wyoming, it should be borne in mind that the conclusions drawn from the data presented do not take into account gas injection methods which might overbalance the effects of close spacing and rapid drilling. Gas injection certainly is an extremely important development to oil operators and merits their most serious consideration.

The relation between the rate of development, initial production, and ultimate recovery in one part of the Burbank field, Okla., is shown in Figure 4. The dates given on each quarter section of the map are the dates on which the leases were sold by the Government through the Osage Indian Agency, and in a general way indicate the date of development. The figures immediately below the dates indicate the total gross oil in barrels produced from each quarter section up to May 1, 1927.

It may be noted that the leases in Sections 15, 22, 23, and 19 were sold in March and June, 1923, and that the rest of the leases shown on the map were disposed of by the Government in April and May, 1924, approximately one year later.

A study of the map shows further that the areas of large initial production follow approximately the section lines between the leases sold in 1923 and those sold during the year following. Initial production rates are an index of ultimate recovery in this field. Moreover, total recovery per quarter section, up to May 1, 1927, is much greater on the leases sold in 1923 even when allowance is made for the probable one year's shorter producing life of the wells on the leases sold in 1924. It is logical to conclude, therefore, that a much greater production would have been obtained

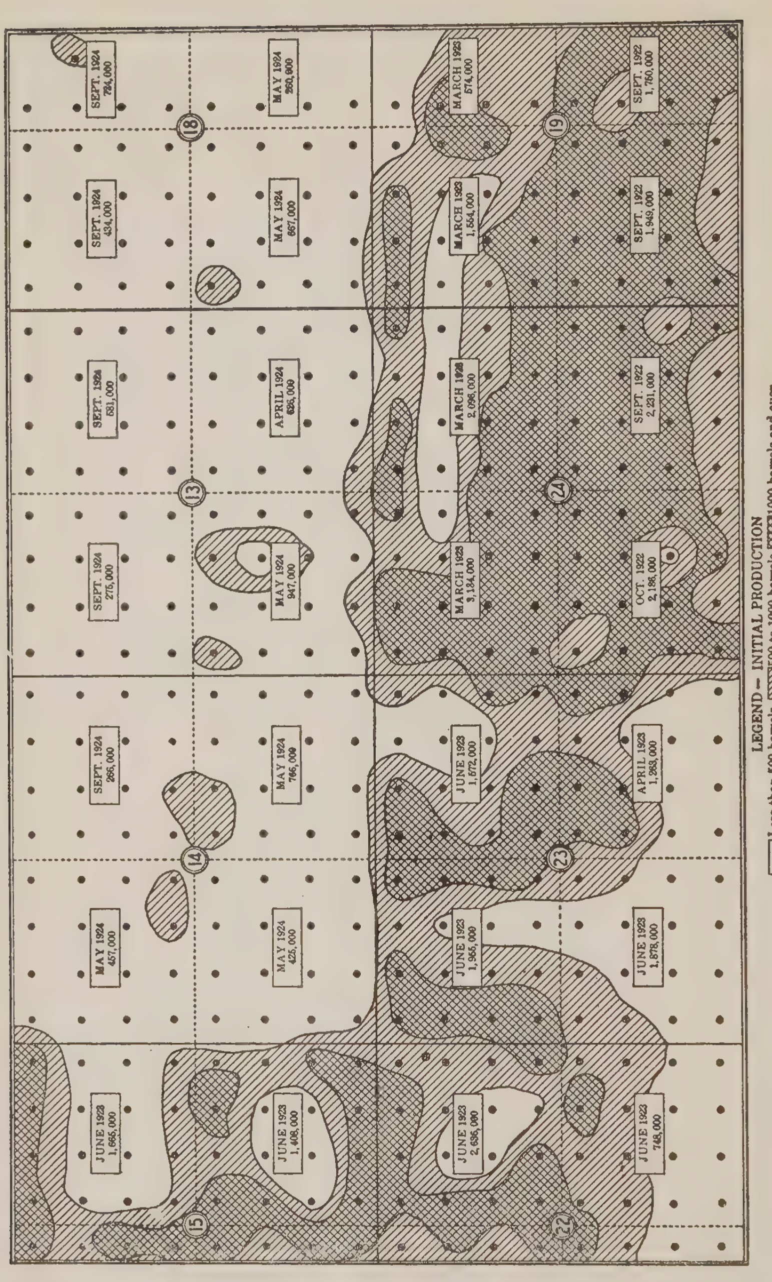

FIGURE 4.—Map showing the relation of initial production and rate of development in a part of the Burbank field, Okla.

from the leases in the south half of Sections 14, 13, and 18, if they had been drilled up at the same time as the leases bordering them on the south.

Seminole City field, Okla., furnishes another example of the effect of the rate of development on the total amount of oil recovered per acre. A comparison of the effect upon the recovery of oil per acre due to rapidly developing and

TABLE 4.—EFFECT OF THE RATE OF DEVELOPMENT UPON THE TOTAL AMOUNT OF OIL RECOVERED UP TO SEPTEMBER 20, 1927, IN A SECTION OF THE SEMINOLE FIELD, OKLA.

Lease No.	Number of barrels of oil recovered per acre up to Sept. 20, 1927	
	Rapidly developed	Slowly developed
1*	......	16,400
2*	......	19,582
2	......	13,141
3*	......	15,880
4	25,007	......
5	23,128	......
6	24,458	......
7	46,598	......
8	26,534	......
9*	23,164	......
10	34,790	......
11	......	16,400

* Leases in same section and adjacent to each other, and having approximately the same initial production when compared as to the time at which they were "brought in."

slowly developing a section of the Seminole field is shown in Table 4.

During the early development of the Salt Creek field, Wyo., several tracts were drilled rather intensively, and these tracts have the highest production per acre to date. It is also reported that current production of these tracts is on the average equal to that of surrounding leases. This report indicates rather definitely, and agrees with the data obtained in the Burbank field in Oklahoma, that the first

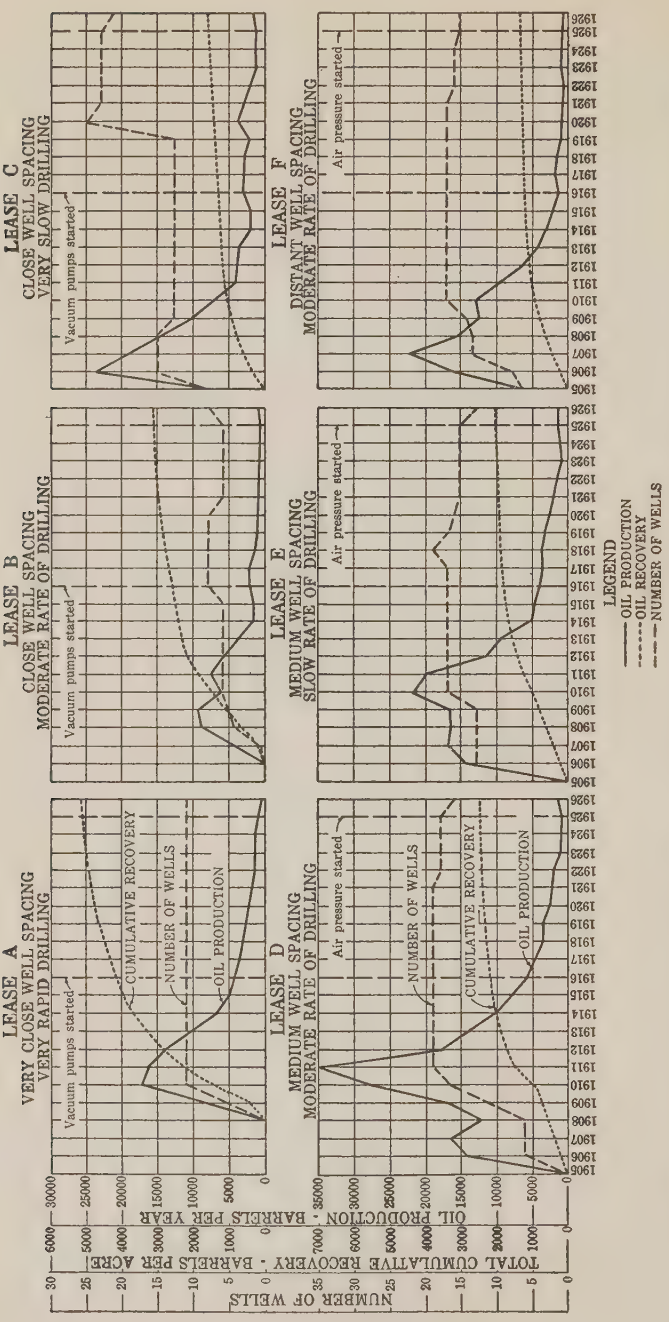

FIGURE 5.—Production graphs of six leases in Nowata and Rogers Counties, Okla., giving data on well spacing and rate of development

wells drilled produce the most oil, other conditions being equal. The remainder of the productive area about these intensively drilled tracts was developed uniformly, and the production per acre is comparatively uniform. Of course, there are certain areas that are known to be more productive than others and that show a high yield even though there was no early drilling, but such results merely show that some areas are naturally more prolific oil-producers than others.

Data pertaining to oil production as related to well spac ing and rate of development on six leases producing from the Bartlesville sand in Oklahoma are shown graphically in Figure 5. Lease A is in Nowata County, and the other leases are a few miles south in Rogers County. The average depth of the wells and the average thickness of the producing sand on each of the leases is given in the following tabulation:

Lease	Average depth of wells, feet	Average thickness of the producing sand, feet
A	450	25
B	400	21
C	400	20
D	400	21
E	400	20
F	400	20

The number of wells per acre and the rate of drilling the various leases differed; as a result, the recovery of oil per acre and per acre-foot of sand was different for each lease. Table 5 gives data pertinent to the well spacing, rate of development, and oil production on the six leases up to January 1, 1927.

The advantages of fast drilling and even of slow drilling followed by gas injection may be overbalanced by the economic advantages of a moderate drilling program and control of gas-oil ratios. If it were possible to control gas-oil

ratios so that oil entered the wells with a minimum amount of gas it would not make any difference how slowly a property was developed, because every barrel of oil would be expelled from the sand by what might be termed a unit gas-oil ratio, and that unit of gas would have done all the work that it could be expected to do. Of course the technic

TABLE 5.—DATA ON THE AMOUNT OF OIL RECOVERED PER ACRE AND PER ACRE-FOOT FOR VARIOUS WELL SPACINGS AND RATE OF DEVELOPMENT ON SIX LEASES PRODUCING FROM THE BARTLESVILLE SAND IN NOWATA AND ROGERS COUNTIES, OKLA.

Lease	Well spacing acres per well	Rate of development	Oil recovered		Remarks
			Barrels per acre	Barrels per acre-foot of sand	
A	1.8	50% first year	5,190	200	Close well spacing
		100% second year			Very rapid drilling
B	2.5	12% first year	3,131	150	Close well spacing
		38% second year			Moderate rate of drilling
		75% fourth year			
		100% tenth year			
C	2.7	30% first year	1,606	80	Close well spacing
		50% second year			Very slow rate of drilling
		100% sixteenth year			
D	4.2	31% first year	2,503	120	Medium well spacing
		58% second year			Moderate rate of drilling
		100% sixth year			
E	4.0	70% first year	2,038	100	Medium well spacing
		85% fifth year			Slow rate of drilling
		100% fourteenth year			
F	5.3	35% first year	1,370	70	Distant well spacing
		76% third year			Moderate rate of drilling
		100% sixth year			

of gas-oil ratio control of oil wells has not yet advanced to a point where unit ratios are possible, but operators are learning a great deal about effective methods of gas-oil ratio control; by continuing their efforts, which in the past have led to consistently successful results in lowering gas-oil ratios, there is a possibility that oil will be produced with unit ratios in the near future.

DRILLING AND COMPLETION METHODS THAT PREVENT WASTE OF GAS

PROTECTING UPPER GAS FORMATIONS

Migration of gas from its original strata to lower pressure formations results in underground losses which often are considerable. Many wells are drilled through sands carrying gas under high pressure before the main producing formation is reached, and loss of gas ensues unless such sands are cased off and the gas is confined. Migration of gas from high to lower pressure strata occurs between the casing and the wall of the hole, and eventually the gas will find its way to the surface or into some porous formation. Imperfect water shut-offs also may cause waste of gas by allowing it to migrate past the shoe of the water string.

Upper sands may be protected and their gas confined by sealing them off with mud fluid and cement or by landing casing above and below the sands. The first of these methods requires less casing, as several formations may often be sealed and protected by a single string; this reduces the cost of wells and allows completing the hole with larger-sized casing.

The gas sands encountered when drilling with rotary tools are " mudded off " by the circulating mud fluid as drilling progresses, usually without change in drilling routine. In cable-tool wells, on the other hand, mud fluid must be placed in the hole immediately before gas sands are encountered by the bit, and drilling must be continued until the sand is passed; the casing must then be landed, with mud fluid behind it, in a suitable landing formation below the sand. If this does not seal off the gas, mud fluid should be circulated through the casing (or tubing that may have been run for the purpose) and back to the surface past the exposed formations that are to be mudded. If circulation of mud fluid fails to " kill " the gas and if a pressure greater than that exerted by a column of mud fluid is required to seal the formations effectively, mudding under

pressure is necessary. The additional pressure must be obtained by the use of high-pressure pumps.

In many wells there is no suitable formation in which to land the casing below the gas sand. Formation shut-offs, unless exceedingly tight, do not always prevent gas, because of its migratory character, from tending to dissipate around the shoe of the water string. This is particularly true when gas pressures are high. The only method that will insure against loss of gas when shut-offs are imperfect and leak is to cement the casing. This subject is dealt with at length in various publications of the Bureau of Mines [11] and will therefore not be discussed in this report.

Another method of sealing off and confining gas in upper sands is to land strings of casing above and below the sands. Here, too, precautions must be taken and suitable formations chosen in which to land the casings so that shut-offs will be tight. Otherwise gas will escape past the upper shoe or around the lower one and eventually escape. If ordinary formation shut-offs cannot be made tight, it will be necessary to mud or cement the casings above the shoes, as is often done when a single string of casing is used to seal off one or more gas sands.

The use of secondhand casing is questionable economy in wells where high pressures are expected. Poor casings may collapse under relatively low pressures. Before old casing is run in the hole it should be carefully inspected for poor threads, splits, dents, and other undesirable features that reduce its strength and effectiveness. Casing and collars with defective threads cannot be set up tight, and in many wells leaky casing joints are a source of gas loss. Even with new pipe, cross threading may occur unless workmen are careful, and gas will be lost through the resulting imperfect casing joints. Such points of weakness in materials and improper handling when "setting up" can be detected

[11] Tough, F. B., Method of Shutting Off Water in Oil and Gas Wells: Bull. 163, Bureau of Mines, 1918, 122 pp. Lewis, J. O., and McMurray, W. F., The Use of Mud Fluid in Oil and Gas Wells: Bull. 134, Bureau of Mines, 1916, 86 pp.

at the surface, and operators should require their crews to make certain that whatever goes into the hole is mechanically perfect.

COMPLETION METHODS THAT PREVENT WASTE OF GAS

Careful observation of known and accepted drilling methods materially aids operators to avoid losses of oil and gas when drilling into high-pressure sands. If wells are being drilled in areas where high pressures are likely to be encountered, precautions should be taken to prevent loss of control of the wells; loss of control usually results in damage to the wells and equipment, often makes operators liable for damages to adjoining property, and at times even causes loss of life. Frequently, especially in wells with open hole, uncontrolled flow permits large amounts of sand to heave into the wells and causes the walls to cave. If the wells are cased there is always the danger that the casing will collapse when wells blow "wild." Thus, in addition to wasting oil and gas, uncontrolled flow often makes it necessary to redrill wells or to abandon them.

Every well drilling in high-pressure area should be fitted with a flow-control device at the top of the casing which will enable the well crew to restrain the flow from the well temporarily until a more permanent method of control can be installed. There are various types of blow-out preventers and control casing heads on the market that are used as precautionary devices for such purposes; by their use many wells that otherwise might have flowed uncontrolled for days, weeks, or even months, have been held in check successfully.

DRILLING IN WITH CABLE TOOLS

At cable-tool wells it is a good practice to place a flow control device on the last string of casing to be landed before the drill is advanced too near high-pressure strata. Such devices do not interfere with drilling and are therefore a constant protection against blow-outs. In Pennsyl-

vania, parts of Oklahoma, and certain Rocky Mountain fields perforated liners (oil strings) are seldom required, as the sands are consolidated and " stand up." In those districts the hole below the water shut-off is left " open " usually, and the oil is permitted to flow through the water string until such time as it becomes necessary to install tubing. In these fields a master gate should be placed on the water string, usually below the derrick floor before drilling in is attempted. If a flowing well is brought in, a control casing head, which is essentially a fitting for a producing well, may be placed above the master gate.

When the sands are loose and unconsolidated, as in California and the Gulf Coast area, an oil string with screen or perforated pipe is set opposite the oil sand to prevent the hole from caving. Usually the wells in such territory are drilled with rotary tools to the water shut-off point and are cemented. After the cement has hardened and the bailing test for water shut-off shows that an effective seal has been made, the cement plug is drilled out, sometimes with cable tools but more often with rotary tools. Care is necessary at this stage of drilling. Many wells have blown out while drilling through the cement plug and while drilling more hole below the shoe into the producing sand. A well that is fitted with a master gate can be held in check and unnecessary losses of gas and oil can be prevented by closing the gate, even if the well blows out before the oil string is run.

It is common practice and an excellent precaution against blow-outs when drilling through loose and unconsolidated sands with cable tools to maintain a column of water or mud fluid in the hole to hold up the walls and control the flow of oil and gas during completion of the drilling-in process. A further discussion of mud fluid will be given in the following paragraphs on rotary drilling methods.

CONTROL OF WELLS DURING DRILLING IN WITH ROTARY TOOLS

The rotary method is ideally adapted to the drilling of wells in areas where formations are soft and cave easily

and where high pressures are likely to be encountered. Drilling through loose formations is possible and expedited by the continuous circulation of mud fluid. The pressure due to the column of mud fluid in the well holds back high-pressure gas and oil and prevents the well from coming in prematurely. The mud fluid plasters the walls of the hole and prevents them from caving, seals off upper gas and oil measures, and carries cuttings from the bottom of the hole to the surface.

The pressure due to the column of mud fluid in the well should at all times be maintained in excess of any formation pressure likely to be encountered by the bit. Drillers must therefore watch the weight of the mud fluid and not allow it to reach the point where it will no longer hold back high pressures. When mud fluid becomes aerated or " gas cut " it should be changed and fresh mud used in its place. A column of mud fluid impregnated with gas may become so lightened that its static pressure is insufficient to overcome the high pressures in the well.

In some wells the gas pressure is so great that ordinary mud fluid weighing on the average from 9 to 12 pounds per gallon will not hold back the gas, and it is necessary to " weight " the fluid. Weighting is done by mixing certain heavy minerals such as hematite (iron oxide) and barite (barium sulphate) with the mud fluid to increase its weight. Mineral-laden muds have been used extensively in California, especially in the Ventura field, in Winkler County, Tex., to some extent in Louisiana, and in Oklahoma at Seminole and elsewhere.

The use of heavy mineral mud in wells at Ventura has been one of the chief factors enabling operators to carry on a successful drilling campaign under drilling conditions which are conceded to be most difficult. The two heavy minerals that have been tried in the Ventura field are barite and hematite. Hematite was finally selected in this field because it can be delivered at Ventura at a lower cost, and the source of supply is more certain.

Thoms [12] reported that the average weight of the rotary mud used in the Ventura field varies from 10 to 11½ pounds per gallon, or from 75 to 86½ pounds per cubic foot. Occasionally mud as heavy as 12¼ pounds per gallon or 92 pounds per cubic foot is used without the addition of heavy minerals. By the addition of the heavy minerals and without increasing the viscosity, the weight of ordinary mud can be increased to as much as 13½ pounds per gallon, or 101 pounds per cubic foot.

Heavy mineral mud is considered a necessity in drilling through the high-pressure gas zones penetrated in the lower portion of the deep wells in the Ventura field, and although its present function in drilling is almost exclusively to combat high gas pressures, it likewise helps to prevent caving of the walls of the hole. Disastrous blow-outs which always waste gas have been prevented entirely by circulating heavy mineral mud.

Barite mixed with ordinary mud has been used in the Kettleman Hills, Kings County, Calif., to combat the heavy gas pressure encountered at a depth of approximately 5,400 feet. At one well the mud fluid was mixed by means of a steam jet in the proportion of one part of barite to three parts of ordinary mud, and the resultant mixture held back a flow of gas under a pressure of 1,200 pounds per square inch. In Winkler County, Tex., large quantities of barite have been used to weight drilling fluids. In many wells the weight of the mud fluid was increased to 15 pounds per gallon (112.2 pounds per cubic foot). A column of this fluid 3,000 feet high will exert at the base a pressure of approximately 2,340 pounds per square inch.

The level of the mud fluid in the well should be maintained, and additional fluid should be added when the level is lowered by the removal of the drill pipe or by migration into porous formations. Failure to maintain mud fluid at

[12] Thoms, C. C., Use of Heavy Minerals in Rotary Drilling Mud in the Ventura Field: Summary of Operations, California oil fields, September, 1926, p. 6.

the proper weight and level and neglect to add additional fluid when coming out of the hole have been the cause of many blow-outs and much loss of oil and gas.

When wells are drilled with rotary tools it is customary to core ahead when the drill almost reaches the depth at which productive sands are expected. Care is necessary at this time to prevent blow-outs. As a precaution and to insure against loss of control of wells when "prospecting ahead" and subsequently drilling into the producing formation with a full-size bit, a blow-out preventer should be in place on the top of the well.

Briefly, drilling methods should be such as to avoid unnecessary losses of gas. Mud fluid and, when necessary, mineral-laden muds should be used where heavy gas pressure is present either above the producing sand or in the sand itself. Upper gas sands should be cased off properly and cemented so that the gas cannot escape either to the surface or into dry or low-pressure sands. Every well should be completed in such a manner that control of the well is assured and blow-outs are prevented. This can be accomplished by accepted and tried methods and with equipment now on the market.

PRODUCTION METHODS INFLUENCING THE EFFICIENT USE OF GAS IN OIL RECOVERY

BACK PRESSURE CONTROL OF OIL WELLS

The lack of early scientific control of flowing wells has been one of the principal causes of the low percentage of oil expulsion from reservoir sands and of the waste of natural gas and its inherent energy. For example, it has been conservatively estimated that in the Burbank field, Okla., alone, at least 20,000,000 additional barrels of oil would have been produced during 1927 if production had been under pressure control. Undoubtedly much production was also lost in the Lance Creek field, Wyo., when oil was per-

manently trapped in the reservoir sands by the rapid encroachment of edge water, due to drainage of gas and dissipation of gas energy through the uncontrolled flow of the first gas wells drilled.

Other examples of losses of oil through lack of back pressure control of flowing wells might be cited, but to do so would be to burden the reader with voluminous statistics. It is sufficient to realize that millions of barrels of oil have been lost through the improper handling of flowing wells. This fact is all the more regrettable because a large percentage of the lost oil might have been saved by the application of scientific back pressure control methods on the wells.

Back pressure control is relatively simple, and yet in the past it has had very little practical application. The chief reason for this is that the majority of operators are not familiar with the benefits derived through its use; in competition with one another for the flush production of a field they flow their wells at the lowest back pressure possible, as this method yields greater present daily production. Back pressure control almost always means lower present daily production (in the flush period of a pool) but it also means greater ultimate productions. Because operators can see the immediate loss but cannot foresee the ultimate gain as clearly, they have been slow to appreciate the benefits of early back pressure control of flowing wells. Also in many instances operators who are familiar with the beneficial results of back pressure control of flowing wells have, in the main, waited too long before applying the method to their wells. Many operators have hesitated to apply back pressure on their wells because divided ownerships of oil fields make it imperative that back pressure control be practiced by all operators in the field in order to derive maximum benefits. One hundred per cent coöperation in back pressure application is difficult to attain, but not necessarily impossible of attainment. Proof of this may be found in the Ventura and Dominguez fields in California, where

operators have coöperated successfully in applying recovery efficiency measures to fields of diversified ownership.

If wells are not properly controlled, the greatest waste of gas energy occurs during the first few weeks or months after the wells are drilled into the productive sands. Especially is this true of the first wells drilled in a new pool. During the early life of wells the gas pressure is usually several times greater than it is a year or so later, and if the pressure from the start is not properly controlled, inefficient expulsion of the oil from the sand results. Gas slips by or by-passes considerable oil within the sand if the wells are allowed to flow unrestrained through the casing. The rapidity with which oil is extracted is an essential factor in connection with the amount of gas produced per barrel of oil. If the oil-gas movement is rapid in the sand, gas will pass the oil and arrive at the well bore without bringing its full load of oil, whereas if some restraint is put upon this gas it will bring additional amounts of oil and increase ultimate production.

By maintaining back pressure on the face of the sand the several effects of rapid decline of pressure are avoided, the viscosity of the oil is kept lower than if no back pressure existed, the growth of gas bubbles is retarded, and by retarding the bubbles and preventing increase in surface tension the resistance due to the Jamin effect is kept at a lower value than would otherwise be the case. Maintaining a back pressure almost always lowers the rate of production by lowering the pressure drop through which the expanding gas acts. However, lowering the rate of oil production by the application of back pressures has the effect of more efficient use of the gas energy by lowering the resistance to flow of oil through the sands. The application of back pressure also restrains the rapid encroachment of edge and bottom waters in many wells, thus permitting the ultimate recovery of much oil which may become entrapped in less porous sand lenses.

BACK PRESSURE CONTROL A COÖPERATIVE PROBLEM

The inefficient utilization or waste of gas from any individual well in a lease or reservoir will affect to a greater or lesser degree the ultimate recovery of that lease or reservoir as a whole. Therefore, to obtain the most efficient utilization of natural-gas energy from a lease or reservoir as a whole, it is necessary that there be a uniform method of operation, such that the maximum utilization of gas energy will be obtained in each of the wells in the reservoir. After exhausting every other means of adjustment, it is desirable, where practicable from the standpoint of lease or field conditions, to close in completely or at least restrict the flow of any well or wells whose recovery ratio is excessive compared to the average recovery ratio of the surrounding wells in the field. This recommendation is particularly applicable where it is known that the gas from a well or wells is being drawn from the reservoir from which the field as a whole is producing and not from overlying gas sands which are not in direct communication with the productive sands of the field.

In the Ventura field, Calif., coöperative operating agreements to control producing operations with special reference to increasing the efficiency of oil and gas recovery and the reduction of field gas surplus have been in effect for several years. As early as the spring of 1927 coöperative conservation measures which affected the field as a whole were successful in shutting in six wells whose gas-oil ratios varied from 7,000 to 28,000; in lowering tubing in a seventh well so that its gas-oil ratio was reduced from 8,700 to 6,900; and in redrilling one well that produced 2,000,000 cubic feet of gas and only 30 barrels of oil a day. From time to time since 1927, back pressure control on other Ventura wells has reduced gas-oil ratios, thereby increasing the efficiency of gas and oil recovery and increasing the amount of oil that will be recovered ultimately from the field. The

success of the Ventura agreement to control certain phases of producing operations can be attributed largely to the coöperative action of all the operators in the field. Their willingness to prorate and at times shut in oil production completely, so as to make more efficient use of the formation gas, is highly commendable and shows that it is possible for operators in a field to coöperate for the good of all.

It has been estimated[13] that by September, 1928, coöperative back pressure control of the wells in the Ventura field, Calif., was effecting the saving of some 91,500,000 cubic feet of gas a day and that this procedure had reduced the field gas-oil ratio from 4,950 cubic feet per barrel—the estimated total field gas-oil ratio if all wells were allowed to produce at normal rates—to about 3,700 cubic feet per barrel of oil produced. To give some idea of the possible value of this decrease in gas-oil ratio, Swigart is quoted as follows:

"Assume that the gas saved will some day produce oil at the rate of 4,000 cubic feet per barrel. This would mean that for every barrel being produced under present methods, an extra 0.29 of a barrel will be produced ultimately; or stated differently, with a present total field oil production of approximately 50,000 barrels per day, ultimate production is being increased at the rate of 14,640 barrels per day by the present methods of gas conservation. Even if the gas were only one-half as effective as at present in driving oil from the sands, the daily rate of increase in ultimate recovery would be 7,530 barrels per day, which is equivalent to an increase in recoverable oil reserves of 15 per cent."

TIME REQUIRED TO RETURN DEFERRED PRODUCTION

The question of the rate of return of deferred production has caused considerable opposition to pressure control of

[13] Swigart, T. E., Practical Application of Back Pressure Control of Flowing Wells: Presented before District Meeting of Division of Development and Production Engineering of the American Petroleum Institute at Los Angeles, California, September 21, 1928.

oil wells and doubt as to the economic soundness of the method. Available data, however, indicate that equal cumulative returns in oil production are usually obtained in a comparatively short time when considered in terms of the life of wells. In fact, when this state of equal cumulative production is reached, the pressure-controlled wells show a much higher daily rate of production, which would indicate a greater ultimate recovery. This is particularly true of flowing wells, whether allowed to flow naturally or by the assistance of extraneous air or gas as in the air or gas lift. In addition to the indicated greater ultimate recovery, the cost of lifting oil is greatly reduced because of increased production obtained during the prolonged flowing life of wells under pressure control.

The decline curve, Figure 6, which is superimposed on the oil production curve of a well in the Thomas field extension, Okla., represents a conservative estimate of the minimum rate of decline that oil production would have taken if no pressure control had been applied. It may be noted on the curves that pressure control was applied almost immediately (June 2) after the well was completed and caused a drop in daily oil production of about 600 barrels, but at the same time it reduced the gas-oil ratio from 810 to about 600. From May 18 to August 25, inclusive, the volume of gas conserved because of pressure control was 63,000,000 cubic feet, a volume with energy sufficient to produce 110,000 barrels of oil on the basis of 570 cubic feet per barrel—the well's average gas-oil ratio during the pressure control period.

It is estimated that by July 5, 48 days after pressure control was first applied, all the deferred production was returned. In addition, and because of pressure control, the average daily rate of production was from 300 to 500 bar-

rels a day greater than it would have been otherwise. This higher daily average rate of oil production is accounted for

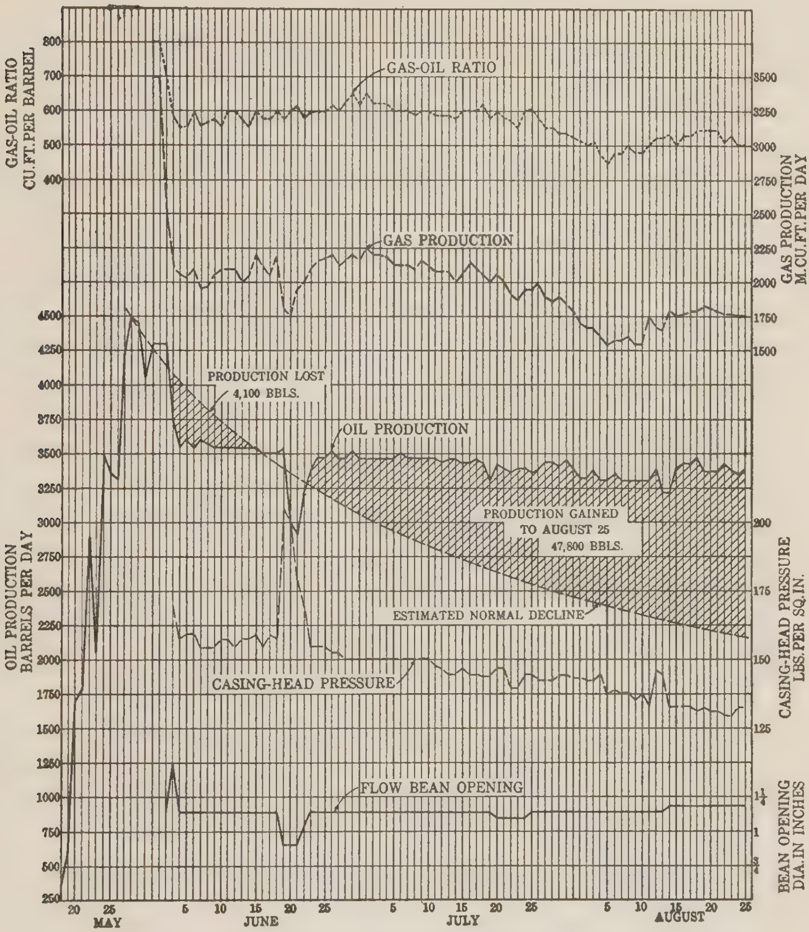

Figure 6.—Production curves of a well under flow bean control in the Thomas field extension, Okla.

by the fact that, because of the large volume of gas conserved in the sand, the reservoir pressure was not dissipated.

Production decline curves of two offsetting wells in the Hubbard field, Okla., are shown in Figure 7. The data shown by these curves are given to support further the contention that deferred production is returned within reasonable time, and also that, even under unfavorable offsetting conditions, pressure control is the more profitable method of production. Both wells produce from the same sand and are similar as regards underground conditions and well completions. The method of operating the wells, however, as will be observed from the data accompanying the curves, was widely different. Well A was completed with an initial production of 640 barrels a day. Well B was completed 67 days after Well A and after deepening had an initial production of 1,278 barrels a day, an amount nearly twice that of Well A.

Pressure control has been applied to Well A—the first well completed—throughout its producing life. The comparative results in cumulative production are shown superimposed on the decline curves. It should be noted that 340 days after Well A was completed, its cumulative production equalled that of Well B even though Well B had double the initial production of Well A. Of equal interest is the fact that production from Well A is being maintained steadily at about 215 barrels a day, whereas Well B has become a very small pumper. These data not only show that deferred production is returned within a reasonable period, but add support to the generally accepted belief that pressure control methods, even under unfavorable offsetting conditions, are means of increasing recovery efficiencies.

Figure 8 shows that there may be a gain in ultimate production even when large flowing wells are beaned back drastically. In the well shown, oil production lost during the first proration period was returned in less than six months, and in November, 1928, actual production was still 50 barrels a day above the estimated production as determined by the well's decline curve.

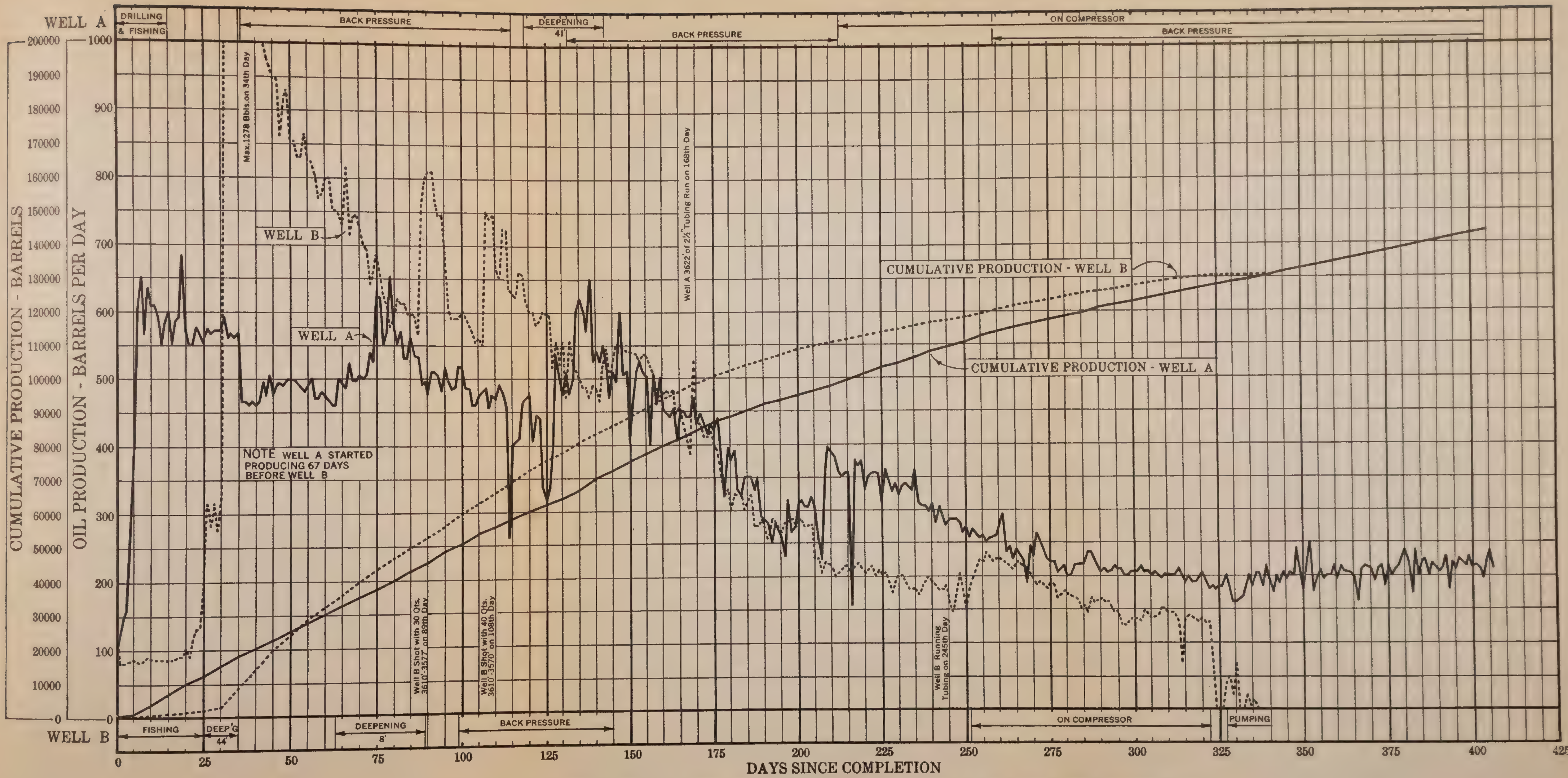

FIGURE 7.—Production data of two offsetting wells in the Hubbard field, Okla., illustrating that pressure control of flowing wells increases production efficiency

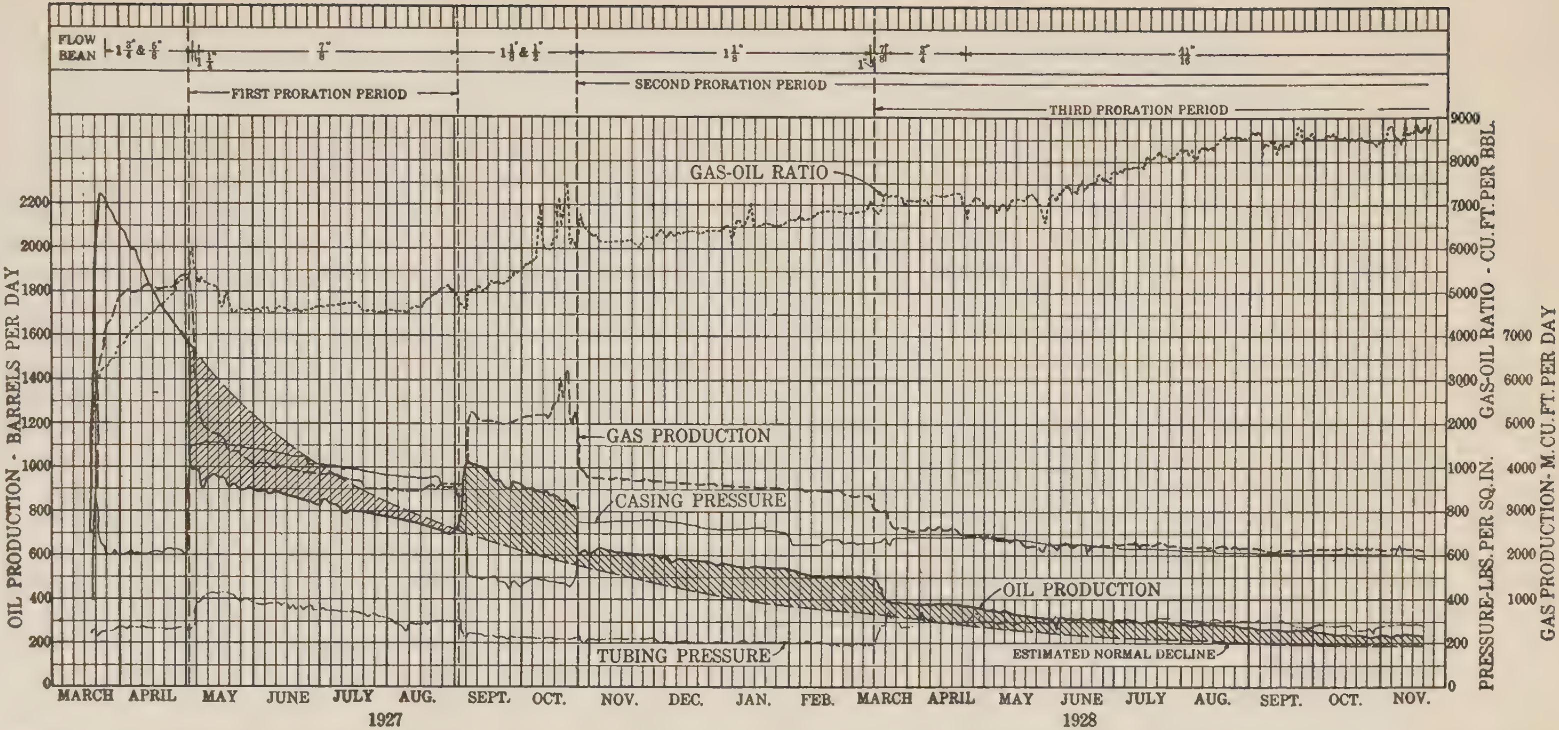

FIGURE 8.—Production graph of a flowing well in the Ventura field, Calif., showing effect of changes in back pressures on oil production and gas-oil ratios, and the ultimate gain in oil recovery as a result of back pressure control

The data shown on Figures 6, 7, and 8 serve to illustrate what can be accomplished if pressure control is intelligently applied, and are presented as evidence to indicate the importance of pressure control and conservation of gas in the production of petroleum. The data bring out further the fallacy of assuming that pressure control methods will always occasion a loss in ultimate production. It is evident also that if sufficient data on a well's performance are available, a close estimate can be made of the point at which the loss incurred in daily production is compensated for in ultimate production.

INFLUENCE OF BACK PRESSURE CONTROL METHODS ON THE CONSERVATION OF NATURAL GAS AND OIL

The regulation of back pressures held against the producing sand is the most important factor in controlling gas-oil ratios. One operator in the Salt Creek field, Wyo., is so convinced that high gas-oil ratio wells are inefficient that he shuts in all wells producing excessive amounts of gas and little oil. The underlying theory for this practice in the Salt Creek field is that as the formation pressure in the wells surrounding the shut-in high gas-oil ratio wells decreases as a result of continued production, the shut-in gas will migrate toward the surrounding wells and drive oil ahead of it. There are a number of high gas-oil ratio wells in the Salt Creek field that are shut in, and although no additional oil production can yet be attributed to shutting in these wells, it is believed that the surrounding wells would have declined more rapidly if the high gas-oil ratio wells had been allowed to produce.

Where flowing wells have a tendency to sand up, and to guard against collapse of the well casing, back pressure control is not only desirable but is essential to the efficient production of wells. Back pressure control is also a means of controlling water encroachment through porous sands

and is a safeguard against premature water encroachment and the breaking of water shut-offs.

It is interesting to note the effect which the holding of back pressure had upon water conditions in two wells in different fields in Oklahoma. One of the structurally lowest wells in the Bramen field was being produced under back pressure, and it was the only low well that did not produce any water with the oil. Even an off-set well, structurally higher and six months younger, produced considerable water. Further evidence to substantiate the belief that back pressure prevented water from entering the well was obtained when, for mechanical reasons, the pressure on the well was released and the tubing withdrawn. Because of difficulty in securing a satisfactory casing head, the well remained open for the next three days. A little water entered the hole on the first day, more on the second, and five barrels on the third day. In the meantime a suitable casing head had been installed, and on the fourth day back pressure was again placed on the well. Water production began to decline immediately, and in a day or two no more water entered the hole.

After five months of continuous swabbing in a well in the Tonkawa field, Okla., during which time production averaged about 600 barrels of clean oil a day, water began to show with the oil. Within 25 days the amount of water produced increased to 50 barrels a day. Swabbing was then discontinued and gas lift applied. Although oil production increased to 700 barrels a day, no water was produced during the following 23 days, undoubtedly because of the back pressure imposed on the producing formation by the gas lift. On the 24th day after the gas lift was applied, water again broke through, and at the end of 3½ months oil and water production was at the rate of 100 barrels of oil and 300 barrels of water a day. The application of back pressure, however, had been effective in holding back water for 23 days, during which time approximately 16,000 barrels of clean oil was recovered.

These two examples indicate that, in some wells at least, it is possible to retard water encroachment by maintaining back pressure on the producing sand in the well and thus recover oil that might otherwise have been lost.

The technic of the application of back pressure as a means of controlling gas-oil ratios is comparatively new. Although back pressure control has been practiced on flowing wells in California and to some extent in other fields almost since the first flowing well " came in," until recently the purpose of such control was to safeguard the well rather than to regulate or control the volume of gas that accompanied the oil to the surface.

One of the most important facts which experience in handling flowing wells has taught is that gas-oil ratios can be controlled more successfully in newly completed wells than in those which have been flowing uncontrolled (not under scientific back pressure control) for several months or years. A possible reason for this is that while wells are producing, drainage channels are formed in the reservoir sands through which gas escapes more readily than oil. It is difficult to control the rate of flow of gas in these passageways so as to affect the gas-oil ratio; consequently, back pressure control is not so effective in old high-gas-oil ratio flowing wells. Such wells must usually be shut in completely to conserve the gas in the formation. Because it is so difficult, or, more often than not, impossible, to lower materially gas-oil ratios in flowing wells when control methods are inaugurated late in the wells' flowing life, the importance of applying pressure control as soon as wells are completed cannot be overestimated.

AMOUNT OF BACK PRESSURE TO CARRY ON WELLS

One of the first questions which arises for the operator, both in point of time and importance, is the question of what back pressure he should hold on his newly completed flowing well.

The amount of back pressure to maintain on a well can only be determined by balancing one set of factors, mainly physical, against another, largely economic, in order to obtain the optimum condition. If the back pressure which is used is too great, the gas-oil ratio will sometimes be increased greatly because of the low velocity of the fluid column and the increased slippage and by-passing of the gas. Too high a back pressure may also be uneconomic in its resulting low rate of recovery of the oil, particularly if the well is closely offset and the neighboring well is being operated at a lower pressure. Production data on a large number of flowing wells indicate that all flowing wells should be produced under pressure control based on actual field tests made on the individual wells as soon as they are completed. Such tests, together with a knowledge of the formation (rock) pressure, permeability of the producing formation, nature of the oil produced, relative volumes of gas to oil and the nature of their association in the sand originally, and the consideration of existing economic conditions, will determine the best method of pressure control with which to effect the most efficient and economic utilization of gas in the production of oil.

RELATION BETWEEN OIL PRODUCTION AND GAS-OIL RATIOS

A study of oil and gas production data brings out the fact that there is a relation apparently between the rate of oil production and the gas-oil ratios of flowing wells, and that the rate of increase of gas-oil ratio in wells where no pressure control is applied is much greater than in wells produced under pressure control. By means of pressure control methods, the rate of increase in gas-oil ratios may be retarded; in some wells it may even be lowered without seriously affecting the daily oil production; usually, however, the decline rate of oil production becomes less and the average daily rate of oil production is more sustained.

Swigart,[14] in discussing the control of gas-oil ratios by back pressure, states:

"A review of individual well production graphs of many Ventura flowing wells for the year 1927 developed the fact that a close relation apparently existed between the trend of oil production of large flowing wells and their gas-oil ratios. In short, it was learned that so long as daily oil production of high pressure flowing wells is declining, gas-oil ratios are usually increasing, and if oil production increases, due perhaps to drastic beaning, gas-oil ratios decrease. In fact, the relation is so marked that it is found in most cases that if oil production maintains a level rate, gas-oil ratios also maintain a level rate and neither increase nor decrease. It seems probable that the critical back pressure for such wells, that is, the operating pressure that gives the best recovery efficiency, is one which results in an oil production at slightly increasing or constant rate."

Figure 8 is a production graph of a Ventura well which " came in " at the rate of 2,240 barrels of oil a day. It may be noted that oil production declined from its peak along a regular and normally shaped decline curve to the beginning of the first proration period, and that during the period of declining production, gas-oil ratios increased.

In accordance with the first proration agreement, effective early in May, 1927, oil production was reduced; as may be noted, this reduction was from 1,575 to 1,000 barrels a day, or almost 37 per cent. Decreasing the size of the flow bean from 1¼ inches to ⅞ inch made this reduction possible. During the succeeding four months, oil production declined at a very gradual rate to about 700 barrels a day. Incidentally at this point the decline curve of actual oil production intersected the normal or estimated decline curve. During this four months' period while oil production was declining, gas-oil ratios first declined, because of the fact

[14] Swigart, T. E., Methods of Effecting Gas Conservation and Increased Recovery Efficiency in Ventura Field, California: Development and production engineering Bull. 202, American Petroleum Institute, Sept., 1928, p. 66.

that the well was adjusting itself to the increased back pressure, and then increased gradually.

The flow bean was enlarged at the termination of the first proration period, and subsequent production, up to October 26, 1927, was through one 1⅛-inch and one ½-inch bean. This change caused oil production to increase from about 700 barrels to almost 1,100 barrels a day. Decline in oil production began immediately at a rate coinciding very nearly with the estimated normal decline rate. Maintaining the flow from the well through larger-sized flow beans allowed the gas-oil ratios to increase rapidly. As shown on the curve, the increase was from 4,700 to almost 7,000 cubic feet per barrel in less than two months.

With the beginning of the second proration period on October 26, 1927, another reduction in oil production was effected by again decreasing the size of flow bean opening. The flow of oil was decreased to 600 barrels a day, and it should be noted that subsequent decline in oil production was at an exceedingly gradual rate up to the time that the third proration program went into effect. Gas-oil ratios decreased temporarily meanwhile, but after two weeks began to climb again at a rate only slightly greater than the rate of increase during the first proration period.

Decreasing the size of the flow bean opening at the beginning of the third proration period from 1⅛ inches to ¾ inch reduced oil production about 100 barrels a day but failed to change noticeably the average rate of increase of gas-oil ratios.

Swigart[15] concludes that "the graph of this well bears out the relation between oil production and gas-oil ratio trends in high-pressure wells, and, moreover, illustrates clearly the close shade of variation in the relation. Fast oil declines are accompanied by rapid increases in gas-oil ratio; slow declines by slow increases in ratio; sustained production by no change in ratio; and increasing production by decreasing ratios."

[15] *Op. cit.*

MEANS OF ADJUSTING AND MAINTAINING BACK PRESSURES IN FLOWING WELLS

The three major methods of adjusting and maintaining back pressure on the producing sands in flowing wells are:

1. Varying the size or cross section area of the tubing or flow string.
2. Varying the depth of the tubing.
3. Varying the pressure on casing or tubing heads at the surface by means of flow beans, flow orifices, trap pressures, stopcocking, etc.

PROPER SIZE OF TUBING

In general it is believed that most wells will be helped in decreasing their gas-oil ratios below the open casing-flow basis by flowing them through proper-size tubing placed at the proper depth.

In a group of 21 new Lakota sand wells that were producing in the Salt Creek field, nine were flowing through tubing with an average gas-oil ratio of 549 cubic feet per barrel. The average daily oil production of these wells was 1,334 barrels. Their individual productions ranged from 166 barrels to 2,800 barrels. The other 12 wells of the group were producing through casing with an average gas-oil ratio of 697 cubic feet per barrel and an average oil production of 1,881 barrels; the individual well production ranged between 177 and 4,455 barrels. Even though all the wells were new and in their flush period of production when every well is most efficient, there was a difference of 21.2 per cent in gas-oil ratios in favor of the tubed wells.

Figure 9 is a segment of the production graph of a well in the Hubbard pool, Okla., illustrating the results obtained by the installation of a string of 2½-inch tubing in a well which had been flowing through 6⅝-inch casing. It may be noted that this change reduced the gas-oil ratio from 1,500 to 1,000 cubic feet per barrel without affecting the daily production of oil.

Flowing a well through casing or too-large tubing, ex-

cepting possibly wells capable of producing several thousand barrels per day, tends toward inefficient use of the gas, due to low velocities and relatively high slippage of gas. Too-small tubing causes velocities that are too high, resulting in high friction losses. Practical considerations as to

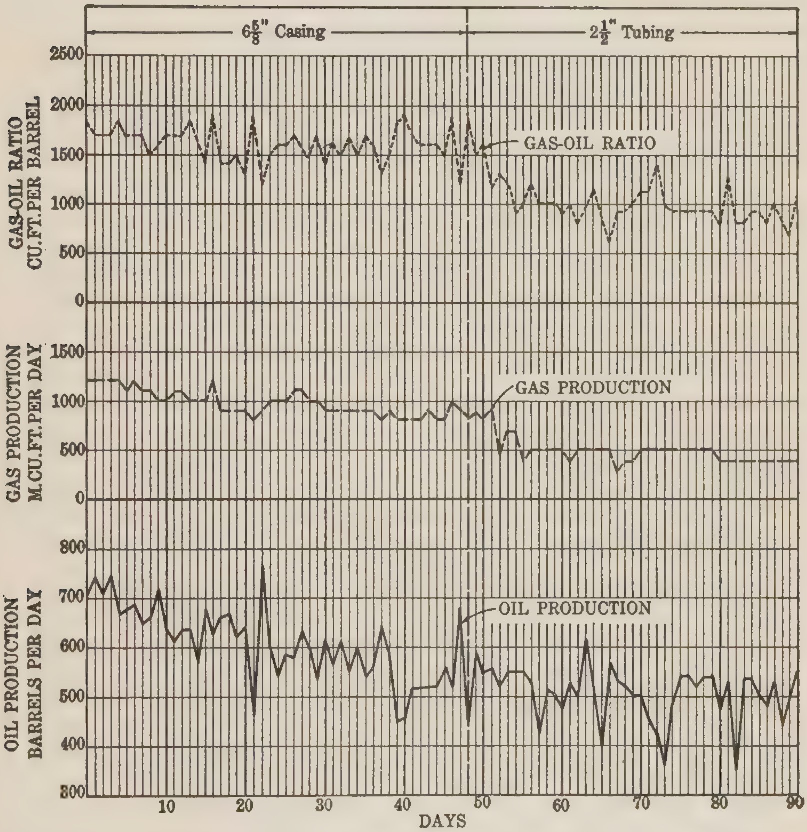

FIGURE 9.—Production graph showing results obtained by the installation of 2½-inch tubing in a well that had been flowing through 6⅝-inch casing. Hubbard pool, Okla.

weight and subsequent use in pumping strings commonly enter largely into the choice of tubing size, and during the flowing life of a well the tubing may easily pass from being too small to being too large, because of decline in rate of production and the accompanying drop in velocities and pressures.

Operators on the Wellington anticline, Colo., found that wells flowing through 2½-inch tubing produced their oil at an average gas-oil ratio of 500 cubic feet per barrel, whereas wells flowing through 6¼-inch casing had an average gas-oil ratio of 1,500 cubic feet per barrel. It was also found that under similar conditions wells will flow for a longer time through tubing than through casing, and that wells which ceased to flow through tubing could be made to flow for some time when a packer was run on the tubing and set above the producing horizon.

Almost all operators in California now flow their wells through tubing. Experience has shown that comparatively high back pressures held on the producing sands improve the efficiency of flow. Inasmuch as tubing of small cross section increases the back pressure against the sands in high-pressure flowing wells, and because back pressure is desirable and necessary to efficient production of the wells, California operators generally use 2½ and 3 inch tubing in their flowing wells.

The correct design of tubing for various depths of wells, pressures, and gas-oil ratios has occupied the attention of many engineers; graduated strings of tubing, small at the bottom and large at the top, and many other special forms have been recommended as better adapted to fit the conditions existing and to effect a more efficient use of the gas energy than the straight string of pipe commonly used. Sufficient data are not available upon which to draw conclusions as to whether or not tapered strings of tubing actually increase the efficiency of flow in oil wells, although it is the consensus of opinion that tapered strings are desirable.

TUBING AT PROPER DEPTH

Tubing once installed in a high-pressure flowing well cannot be readily or safely changed or have its depth altered without killing the well. Usually this is not practical, and it is necessary, therefore, to tube wells at the start in such

a manner that they will operate efficiently and satisfactorily until the pressure has declined to a point where it is practical to change the depth of the tubing.

Proper tubing depths in flowing wells is a problem of which the solution depends upon the adoption of an average depth that will give the greatest efficiency during the period of flush production until the time when it is safe and practical to change the tubing depth. Large flowing wells will flow satisfactorily when tubed either at some point above the top of the producing sand or at some point below the top of the perforations opposite the oil sand; but these same wells, after the period of flush production is past, will flow efficiently only when tubed below the top of the perforations. Maximum flowing efficiency, up to the time that the tubing may be lowered, will therefore result by tubing flowing wells to a point below the top of the perforations and preferably well toward the bottom. The only disadvantage in connection with this practice is the danger that a collapsed oil string might hold the tubing and render a fishing or redrilling job more difficult. This danger, however, is largely confined to California wells where long strings of perforated pipe are set through the thick oil zones.

Proper tubing depth affects chiefly the efficient use of gas energy in lifting the fluid to the surface after it reaches the well. A well tubed too high flows inefficiently, since considerable opportunity is allowed for separation of oil and gas in the casing before the mixture enters the tubing; also the expansion and separation are less effective in raising the oil in the larger cross section than in the smaller. Comparative data, particularly from the Huntington Beach field, Calif., upon similar groups of wells showed the following advantages for the well tubed low:

1. Longer flowing life.
2. Better sustained production.
3. Lower gas-oil ratio.

The third result may be considered as the cause of the other two, or as the promise of still longer life and better sustained production to come. No greater production difficulties, such as sanding up tubing, have been experienced in wells tubed low than in the other wells. In fact, tubing

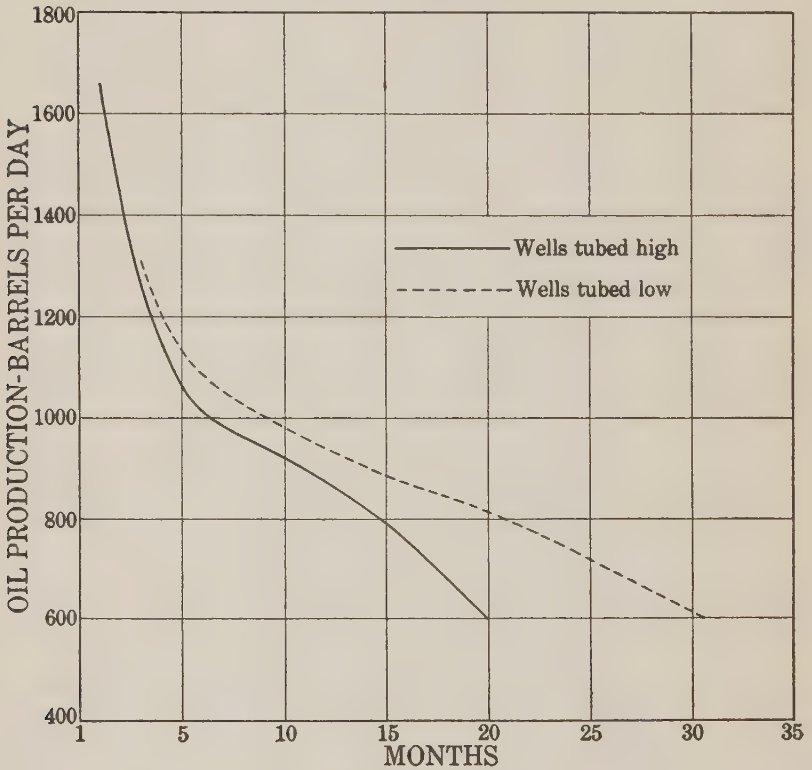

FIGURE 10.—Decline curves showing advantage of tubing wells low. Huntington Beach field, Calif.

set near bottom tends to keep the hole clean of sand, as the sand flows out with the oil as fast as it enters.

Figure 10 shows graphically the advantage of tubing wells low. The data incorporated in these curves represent results obtained at 10 wells on one property in the Huntington Beach field, Calif. Four of the wells were tubed high

and the others low. Lack of information prevented carrying the curves below production of 600 barrels per day.

In the Long Beach field, Calif., tubing was lowered in two wells with good results. The production of one well was about 420 barrels, when suddenly it declined to 138 barrels a day. The tubing was lowered in this well from 2,543 to 3,039 feet, at which point it was about 152 feet below the top of the perforations in the casing; production increased at once to over 440 barrels per day, and the casing pressure which had declined to about 60 pounds per square inch increased to 130 pounds. After the tubing was lowered the well flowed for about one month, during which time it declined from 440 to 200 barrels per day. The tubing change had evidently been made too late to obtain the best results.

In another well in the Long Beach field, oil production declined in two weeks from over 700 barrels a day to less than 130 barrels per day. The tubing was thereupon lowered from 2,790 to 3,500 feet, or to 832 feet below the top of the perforations in the casing, and the well started flowing again at more than 475 barrels per day.

These two Long Beach tests bear out the opinion quite generally held by production men and engineers that lowering the tubing in flowing wells will result in higher casing pressures and therefore in increased flows of oil. They also show that to obtain lasting results, the lowering of the tubing should not be delayed until the well is almost dead.

Figure 11 is a segment of the production graph of a well in the Dominguez field, Calif., in which the tubing was lowered. The rate of decline of oil production was less after the tubing was lowered, due undoubtedly to the more efficient utilization of the formation gas as evidenced by the reduced gas-oil ratios following the tubing change. The gas-oil ratios dropped abruptly during the first 16 days following the change in tubing depth; although they increased again during the succeeding days, they never quite reached their previous high point during the period covered by the

curve. It is evident, however, that the rapid rate of increase in gas-oil ratios which was effective before the tubing was lowered was definitely checked, at least temporarily. Also the upward trend in gas-oil ratio was broken, and the ratio after lowering the tubing did not increase further.

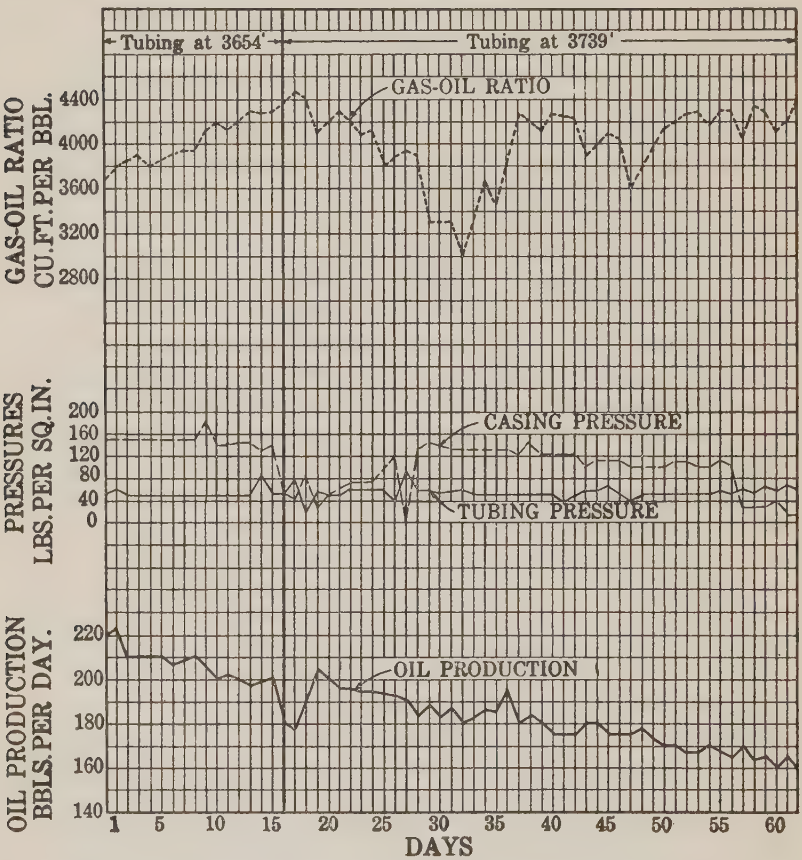

Figure 11.—Graph showing effect of lowering tubing on production, well pressures, and gas-oil ratios for a well in the Dominguez field, Calif.

A test on a 2,000-foot well, producing from the Second Wall Creek sand in the Salt Creek field, Wyo., shows that there is apparently a relation between tubing levels and efficient flow in small flowing wells. This well was producing 168 barrels of oil a day with a gas-oil ratio of 3,459

cubic feet per barrel through 2-inch tubing set at the top of the producing sand and packed off at the casing head. The tubing was then lowered 23 feet, so that the bottom of the flow string was 23 feet below the top of the producing sand. When allowed to produce in this manner, the well gave 152 barrels of oil per day, at an increased gas-oil ratio, which after the change amounted to 3,994 cubic feet per barrel of oil.

This test shows that altering tubing depths makes a difference in gas-oil ratios, and that apparently the best level at which to set the tubing is at the top of the producing sand. However, conclusions based on such meager data as a gas-oil ratio before and after a tubing change are not sufficiently supported and may or may not be correct. Slightly higher gas-oil ratios subsequent to a tubing change do not indicate necessarily that the change was not a good one. Gas-oil ratio trends before and after a change are really the important data and reveal whether tubing changes were beneficial or harmful. If the upward trend of gas-oil ratios is broken by altering the tubing level or if subsequent trends are downward, the change was beneficial even though the gas-oil ratio on a day or two immediately following the change was slightly above the ratio on the day before. On the other hand, any change that results in a more rapidly increasing gas-oil ratio rate is harmful and leads to decreased ultimate recovery.

Although tubing depths apparently affect gas-oil ratios and are altered with beneficial results in some wells, it appears from the data of many flowing wells that lowering tubing does not always benefit recovery efficiencies. Even when gas-oil ratios are apparently benefited by a tubing change, it is seldom that the good effects are permanent. Changes in back pressure resulting from altering tubing depths in large flowing wells are usually slight and seldom are great enough to have a pronounced effect on gas-oil ratios. The control of back pressures on flowing wells by

means of flow beans is a more dependable method, and one which, by directly affecting the differential pressure at the face of the producing sand, usually causes definite changes in gas-oil ratios and their trends.

Tubing depths are important, however, especially in small flowing wells, and affect the efficient use of gas energy in lifting the oil after it enters the well. Slippage of gas through oil is greater in casing than in tubing of smaller diameter; a well tubed high allows considerable separation of oil and gas before the fluid reaches the tubing. It is believed, therefore, that small flowing wells will recover more oil ultimately if they are tubed with small-sized tubing set deep in the hole.

PRESSURE CONTROL BY FLOW BEANS

The use of flow beans has been the most widely employed method of applying pressure control to oil wells; it has been the most successful method in the majority of cases. The accepted practice is to place the flow bean in the flow line close to the well head and upstream from the oil and gas separator.

Tests conducted on certain wells in the Mid-Continent area and elsewhere show that a considerable reduction in the gas-oil ratio is obtained when wells are allowed to flow against the proper back pressure. The tests also showed that when back pressures greater or less than those pressures which gave the minimum gas-oil ratio are applied, the ratio increased. In making the Mid-Continent tests to determine the proper back pressure and size of opening with which the most efficient results are obtained, the flow of oil and gas from the wells was restricted through a range of flow bean sizes. From the data obtained during the tests, the proper back pressures and flow bean sizes for these particular wells were obtained for that time in the life of the wells.

Figure 12 was drawn from data taken on a well in the Thomas field extension, Okla., and shows that a consider-

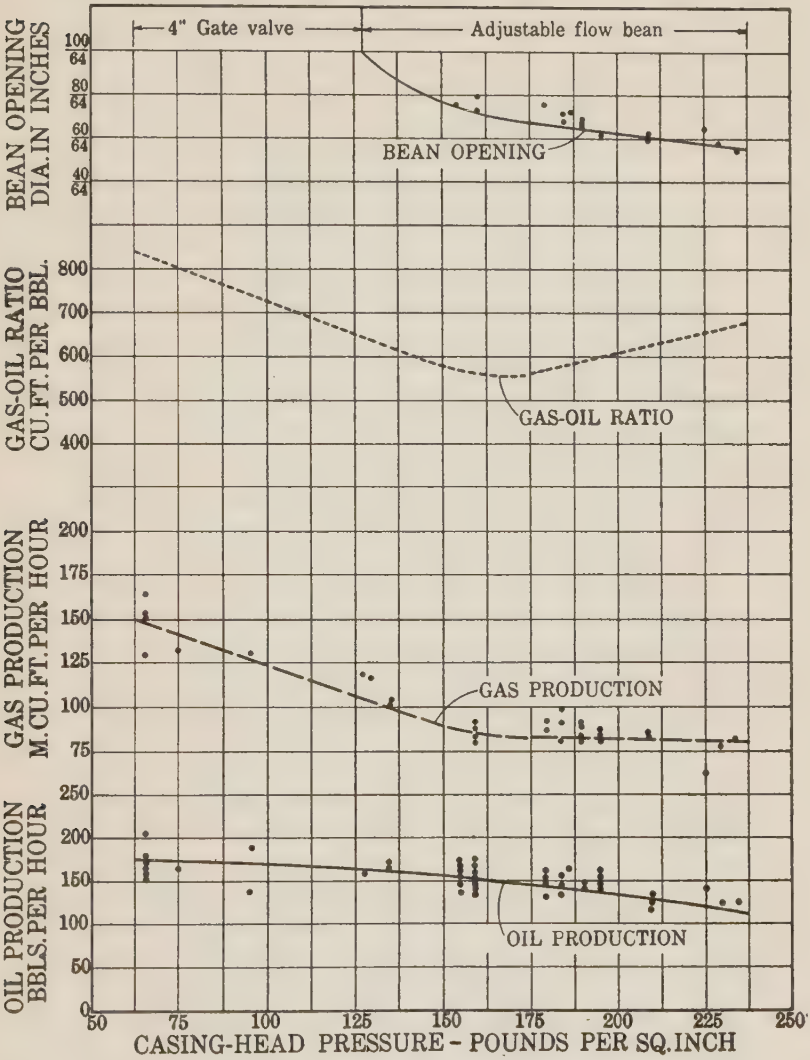

FIGURE 12.—Gas and oil production, and gas-oil ratio data obtained by flow bean test on a flowing well in the Thomas field extension, Okla.

able reduction in the gas-oil ratio was obtained at the proper back pressure. The curves show definitely that for this well

there is a critical back pressure above and below which the gas-oil ratio increases. After determining the back pressure at which this well flowed most efficiently, subsequent production was maintained under pressure control, holding the back pressure as near the critical point as possible. Figure 6, page 75, illustrates the effect that the application of back pressure control, starting on June 4, had upon the gas-oil ratio and upon the rate of decline in oil production as determined by the tests shown in Figure 12. Figure 6 shows that the low gas-oil ratio was maintained throughout the period covered by the graph. Although a considerable drop in daily oil production followed the application of back pressure control, subsequent decline was very gradual.

The following figures give a comparison of the average gas-oil ratios for the various periods covered by the production graph shown in Figure 6:

TOTAL PRODUCTION, MAY 18 TO AUGUST 25, INCLUSIVE	
Oil, barrels	337,946
Gas, M cubic feet	204,321
Gas-oil ratio	606
PRODUCTION PRIOR TO JUNE 4, AND BEFORE PRESSURE CONTROL APPLICATION	
Oil, barrels	53,194
Gas, M cubic feet	42,118
Gas-oil ratio	792
PRODUCTION AFTER PRESSURE CONTROL APPLICATION	
Oil, barrels	284,752
Gas, M cubic feet	162,203
Gas-oil ratio	570

The deduction may be made from the above data that the amount of gas conserved by pressure control of this well was equal to 63,215,000 cubic feet. This volume of gas is sufficient to produce 110,903 barrels of oil at a gas-oil ratio of 570. It is estimated that by controlling the gas-oil ratio in this well, 47,800 barrels of oil less 4,100 barrels, (the amount lost between June 4 and 15) or 43,700 barrels of additional oil, was recovered up to August 25. Furthermore, the decline curve of this and other wells in the same area indicates that without back pressure control the daily

rate of oil production on August 25 would have been about 2,100 barrels, whereas under pressure control the production on that day was 3,400 barrels—a net gain of 1,300 bar-

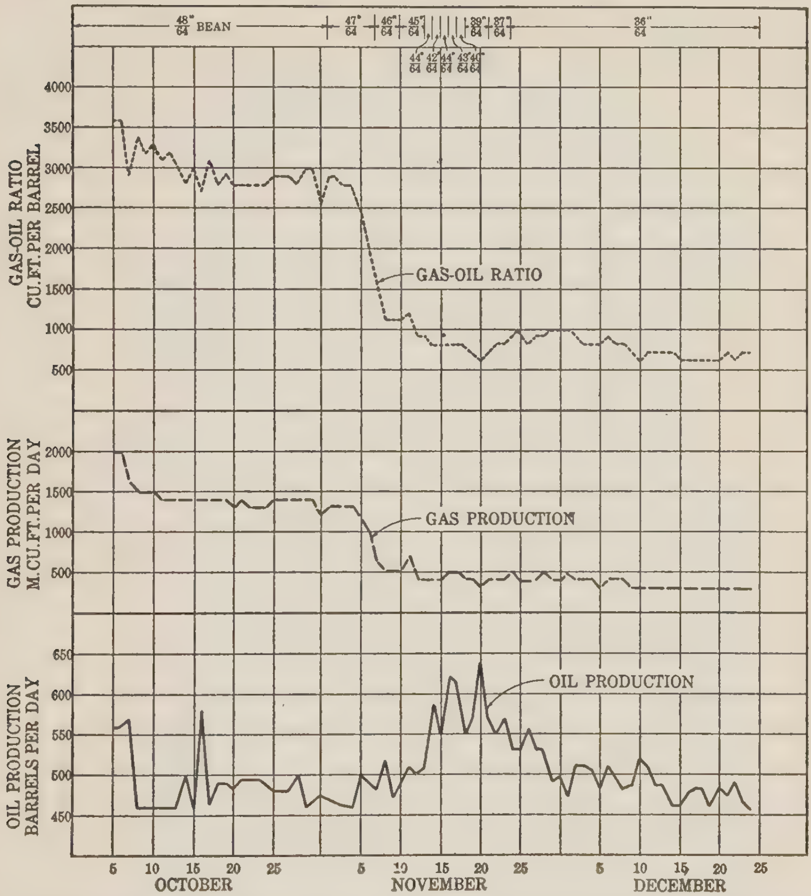

FIGURE 13.—Production curves of a flowing well in the Hubbard pool, Okla., which averaged about 500 barrels of oil a day under back pressure control applied by means of flow beans

rels in daily production. There can be no question that a large gain in ultimate oil production will be the result of pressure control in this well.

Figure 13 shows production data of a flowing well in the Hubbard pool, Okla., and illustrates an example of success-

ful pressure control by means of flow beans in a well whose production averaged about 500 barrels a day. Flow beans were installed on this well during the flush production stage, and the gas-oil ratio was maintained at the critical point throughout the flowing life of the well. It is interesting to note that the gas-oil ratio was reduced from about 3,000 to less than 1,000 by merely reducing the diameter of the flow bean opening from 48/64 inches to about 40/64 inches, and that this change increased rather than decreased the daily production of oil.

California operators have been flowing wells against beans for many years. At first the purpose of equipping wells with flow beans was to prevent the wells from sanding up, to safeguard them against collapse of the casing, and in a measure to control the flow of encroaching edge water. In order to prevent sand from " heaving " into the wells it is necessary to restrict the flow in flowing wells that produce from loosely consolidated sands such as are found in the California oil fields. Maintaining production is difficult when wells sand up frequently. Increasing the effective back pressure in deep wells safeguards the wells against collapse of the casing and likewise prevents the breaking of cement water shut-offs. High back pressures are effective, and one of the purposes of beaning wells is to create high back pressures to control irregular water encroachment; water is a problem in the California fields where the oil sands are exceedingly porous and practically all are flanked by edge water. Recent practice has added the control of gas-oil ratios to the list of purposes for which California wells are beaned.

Most wells in California which belong to progressive operators are now operated under pressure control in a manner that is conducive to low gas-oil ratios. Exceptions are certain wells on small parcels of land in town-lot areas which are flowed " wide open " in order to compete with neighboring wells which are likewise flowed practically

"wide open." High back pressures are being maintained in many wells for the express purpose of reducing the volume of gas that accompanies a barrel of oil to the surface. Thus the efficiency of expulsion of oil from the reser-

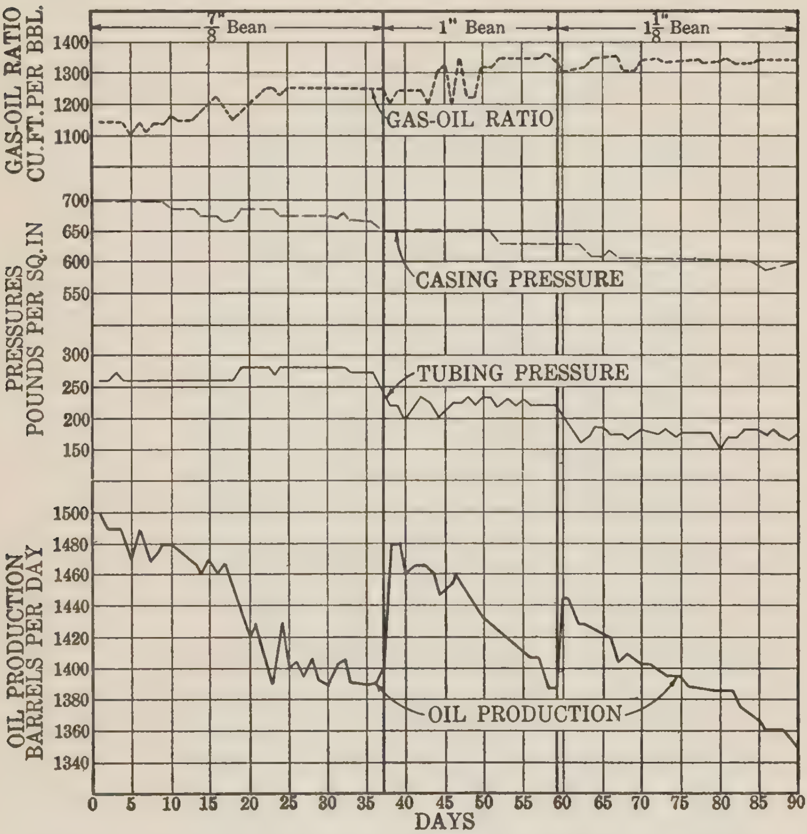

FIGURE 14.—Production data showing effect of changing size of flow bean on a flowing well in the Brea field, Calif.

voir sands is increased. In the Ventura field, for example, back pressures of 1,000 to 1,200 pounds per square inch are common and result in materially reduced gas-oil ratios (see figure 8, p. 77).

Figure 14 is a segment of a daily production graph of a well in the Brea field, Calif., in which the size of the flow

bean was enlarged in an endeavor to increase production and to determine what effect flowing the well against larger beans would have on gas-oil ratios. The well flowed through 3,482 feet of 2½-inch tubing during the period covered by the graph. Increasing the size of bean opening from ⅞ inch to 1 inch increased production by 80 barrels a day. This change, however, increased the daily average rate of decline of oil production from 1.6 barrels a day to 3.6 barrels a day. Gas-oil ratios increased slightly after increasing the size of bean opening, and their trend was upward at a slightly increased rate subsequent to the change. This is to be expected, since by enlarging the bean opening the back pressure decreased and since gas-oil ratios usually increase when the differential pressure at the face of the producing sand is intensified.

After allowing the well to flow against the 1-inch bean for 22 days the bean was changed, and one with an opening 1⅛ inches in diameter was installed. Oil production again increased, but this time the increase amounted to only 55 barrels a day. Subsequent decline in oil production while the well was flowing against the 1⅛-inch bean was at the rate of 3 barrels a day.

Although the changes in bean size did not greatly affect the slightly normal upward trend in gas-oil ratios, it is evident from the curves that the decline in oil production was materially hastened by increasing the area of bean openings. It may be noted that oil production just prior to installing the 1-inch bean was fairly constant at about 1,400 barrels a day with the gas-oil ratio practically stationary at 1,250 cubic feet per barrel of oil produced. It may therefore be assumed in retrospect, that a very gradual decline in oil production and an arrested increase in gas-oil ratios would have resulted if the flow from the well had continued against the ⅞-inch bean.

Tests were conducted to determine the effect on gas-oil ratios of "pinching" wells producing from the Lakota

sand in the Salt Creek field, Wyo. The pinching was accomplished by beaning. The following data show that pinching did not help to reduce the gas-oil ratios in all the wells. However, two wells out of the six did benefit by this treatment.

Number of wells used in test	6
Average gas-oil ratio, 100 per cent production	365
Average gas-oil ratio, pinched-in production	430
Number of wells showing reduced gas-oil ratios when pinched-in	2
Reduction in gas-oil ratio	33 per cent
Number of wells showing increased gas-oil ratios when pinched-in	4
Increase in gas-oil ratios	38 per cent

One well produced nothing but gas when pinched in to the extent of having a back pressure above 700 pounds per square inch. Another pinched-in test was made about six months later on four of the same wells. In this second test, the gas-oil ratio increased in one well, decreased in another, and remained practically the same in the other two. These Salt Creek tests show that back pressure control by beaning at the surface is not effective in all wells, and that it is necessary at times to use other beaning methods, or other methods such as altering the depth or size of the tubing, or both, in conjunction with beaning, to reduce the gas-oil ratio in certain wells.

PRESSURE CONTROL BY FLOW BEANS AT BOTTOM OF TUBING

Some production engineers are of the opinion that the proper place to bean a flowing well is at the bottom of the tubing. They believe that a restriction placed at the bottom of the tubing will cause the tubing to serve as an expansion chamber and allow a more complete expansion of the gas against the oil after it has passed through the flow nipple. A sufficient number of tests with the flow bean at the bottom of the tubing have not been made to form any definite conclusions one way or the other. There is now on the market an adjustable flow bean for use at the bottom of the tubing. Adjustment of the size of the flow opening is made on the

derrick floor by revolving the tubing which is suspended from a swivel casing head. Interesting data will be available, no doubt, after a number of these adjustable flow beans have been installed and tried in different wells in various oil fields.

One well on the Wellington anticline, Colo., was equipped for a time with an adjustable flow bean at the bottom of the tubing. No satisfactory results toward decreased gas-oil ratios were obtained because the test from which conclusions were drawn was too short to determine definitely the effect of bottom hole beaning. It is understood that good results were obtained in several wells in California by the use of adjustable flow beans at the bottom of the tubing, but substantiating data are not available for inclusion in this report.

Extensive tests on flowing wells with an adjustable flow bean on the bottom of the tubing should give interesting and worthwhile data that might prove valuable to engineers and production men. It is hoped that such experiments will be made and the results published.

PRESSURE CONTROL BY GATE VALVES AT TOP OF TUBING

A series of tests were made in the Salt Creek field, Wyo., using gate valves at the top of the well in place of flow beans to control the volume of gas that accompanied the oil to the surface. In a group of eight wells, 15 casing " pinches " were tried. In only five of these tests was the gas-oil ratio reduced below the wide-open casing flow basis. The conclusions drawn from the pinching tests were that, in general, flowing wells in the Salt Creek field wasted gas when " pinched " by gate valves, and that it is inadvisable to produce flowing wells at a rate less than the open flow capacity by " pinching " with gate valves, unless it is known definitely that the gas-oil ratio has not been increased thereby.

Similarly conducted tests to control tubing flow by means of gate valves at the tubing head indicated that some wells

will yield reduced gas-oil ratios with tubing-flow "pinches" and others will not. It was concluded from the results of these tests that there is no definite relationship between back pressure control as applied by gate valves and gas-oil ratios. Each well must be experimented with individually and trial tests made to determine the conditions for efficient flow.

PRESSURE CONTROL BY STOPCOCKING

Stopcocking is a method of controlling gas pressures in oil wells by keeping the well closed in and the gas confined except during stated intervals when the oil is flowed or pumped. Stopcocking will frequently keep a well flowing that otherwise would have to be pumped. It thus has a further advantage in reducing lifting costs and operating expenses.

Stopcocking is an old method of producing oil and was developed many years ago in some of the old Pennsylvania fields where wells produced relatively small amounts of oil but built up considerable gas pressure when shut in. It is not often used at the present time on flowing wells, and few data are available on its use as a method of controlling back pressures.

A few tests made in the Salt Creek field, Wyo., indicated that for small flowing wells certain methods of stopcocking greatly reduced the gas-oil ratios with increase of production of oil. Stopcocking on small wells equipped with 2-inch tubing yielded good results in reducing gas-oil ratios; although the rate of oil production was below what the wells would have flowed wide open through casing, the efficiency of flow was increased materially. Stopcocking was of further value in that it eliminated paraffin trouble in the wells.

Figure 15 shows graphically the data taken during a stopcocking test on a well producing 50 barrels a day in Carter County, Okla. By obtaining data at several combinations of pressure, it was found that the gas-oil ratio in this well could be reduced from 1,350 to 1,060, or by 21 per cent,

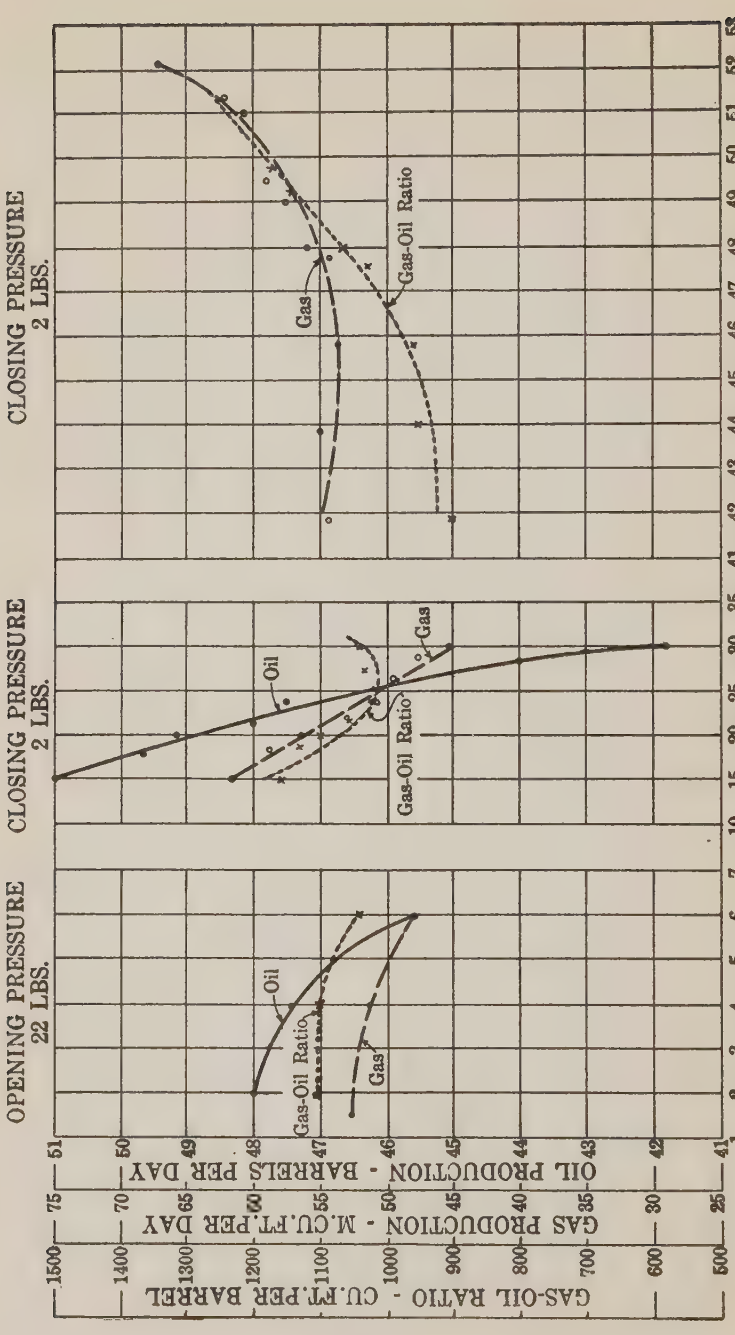

FIGURE 15.—Oil and gas production, and gas-oil ratio data obtained during a stopcocking test on a 50-barrel well in Carter County, Okla.

with a drop in oil production of only 5 barrels a day, or 10 per cent. It is evident from the data shown in B, Figure 15, that by stopcocking, a critical point in back pressure application is reached, similar to that obtained by flow beans, above and below which the gas-oil ratio increases.

THE GAS LIFT AS AN AID TO EFFICIENT USE OF RESERVOIR GAS ENERGY

Inasmuch as the principal object in gas conservation is the control of the recovery ratio, and inasmuch as that ratio represents the sum of the energy required to bring oil into the hole plus that required to lift the oil to the surface, it is apparent that supplementing the lifting energy by gas lift will relieve the formation of a certain expenditure of gas energy which might be put to better use in bringing more oil into the hole. The mechanics of gas-lift flow and the methods of control differ from those in a flowing well only in that the gas lift provides a ready means of altering the effective back pressure by varying the volume of gas circulated.

Many operators have adopted the gas or air lift primarily to obtain the greatest possible current daily production. In most instances this is a short-sighted policy. Flowing gas-lift wells only for the purpose of increasing daily oil production results usually in a large increase in gas-oil ratios and a rapid decline in oil production. Efficiency in the production of oil decreases with increasing gas-oil ratios; the progressive operator will not sanction the production of oil at a sacrifice of ultimate recovery occasioned by an increased gas-oil ratio. Experience has shown that gas-oil ratios can be controlled in gas-lift wells by regulating the effective back pressure, and that such control is as important in gas-lift wells as in those which flow naturally. For instance, in the Dominguez field, Calif., the application of controlled back pressures by means of the gas lift and regulated back pressure decreased the formation gas-oil ratio of a well

from 2,400 to 1,037 cubic feet. This is a reduction of about 60 per cent in gas-oil ratios and means much toward increasing ultimate recovery of oil from the well.

PROPER TIME FOR INSTALLING THE GAS LIFT

Gas lift may be applied at any stage of the well's production, but it is seldom useful during the flush period of natural flow. The gas that accompanies the oil into the wells during the flush flowing stage is generally under relatively high pressures and already contains more than enough energy to lift the oil to the surface. The addition of extraneous gas at that time is usually unnecessary and of no particular advantage.

The normal life of a well may usually be divided into three critical periods, according to the mechanics of flow and its production efficiency:

1. A period of flush flowing production, when by reason of an excess of gas and oil and a relatively high reservoir pressure it is usually possible to control the effective back pressure to secure a reasonable degree of producing efficiency.
2. A period of intermittent flow, when by reason of a deficiency in gas there is insufficient energy to flow the well steadily and when the gas must collect and build up "heads" before the well again flows. There is little back pressure control possible at this stage. Because of the surging nature of the flow and tendency of the gas to bypass, this is as a rule the most inefficient period in the life of a well.
3. A period when there is insufficient reservoir energy to flow the well either steadily or by heads, and natural energy must be supplemented by mechanical means.

Where the gas lift is to be used in a well, it should be installed as soon as the well enters the second flowing stage. It will thus entirely eliminate the period of intermittent flow from the well's producing history.

In the application of the gas lift it is only necessary that the pressure required to lift the oil be less than the reservoir pressure, or mean effective reservoir pressure, at the wall of the hole opposite the zone which will be produced. Flowing pressures in gas-lift wells are governed by the type, diameter, and length of the flow tubing; the volume of gas or air circulated; and the physical properties of the oil-gas mixture after it reaches the well. Flowing pressures vary in the average well from about 4 pounds to about 8 pounds per square inch per 100 feet of flow line. Flow in many wells is maintained by gas-lift through 3,000 or 3,500 feet of tubing with circulated gas pressures around 125 to 150 pounds per square inch. It is possible, therefore, to use the gas lift for a long time in some wells before reservoir pressures decline to such a point that the differential pressures at the faces of the producing sands become so low as to seriously affect the flow of oil into the wells.

EFFECT OF GAS LIFT ON GAS-OIL RATIOS

Variation in gas-lift practice is so great that it is impossible to make generalized statements in regard to the effect of gas lift on gas-oil ratios.

Where wells were flowing prior to the installation of the gas lift, it would be expected that the introduction of compressed gas to assist in raising the oil would decrease the necessary formation energy and thus decrease the gas-oil ratio, unless the increase in production rate and decrease in pressure were so great as to disturb the existing relations of friction and viscosity in the sand.

In the Wellington field, Colo., and in the Lost Soldier field, Wyo., the gas lift resulted in reduced gas-oil ratios, increased oil production, and less shut-down time than when the wells were on the pump. Although no data are available as to the effect of the gas lift on ultimate production, the fact that there is a conservation of gas indicates increased ultimate recovery of oil from reservoir sands.

One company operating in the Huntington Beach field, Calif., reports that in 12 wells that were put on the gas lift while flowing, 9 showed decreased gas-oil ratios, one showed practically no change, and the records of at least one of the others were unsatisfactory. Other companies in the same field and operating a large number of gas-lift wells found that the recovery gas-oil ratio is usually somewhat lower than that prior to the installation of the gas lift.

In the Mid-Continent fields, as in California and elsewhere, the change in operating status from natural flow to air or gas-lift flow often changes the gas-oil ratio. Where no pressure control is applied subsequent to the change in operating methods, the gas-oil ratios may be up or down, as the increase or decrease is entirely accidental as far as operating conditions are concerned. However, where pressure is controlled by means of flow beans, by varying the volume of inlet gas, or by altering the size and depth of eductor tubing, the gas-oil ratio usually is lowered.

Gas-lift experiments in the Wellington-Fort Collins district, Colo., showed that certain wells which were making more fluid than ordinary pumping equipment could handle, produced more fluid by the gas lift with a lesser gas-oil ratio. The following tabulation of production data on one well in the Fort Collins field shows that as far as recovery efficiency is concerned the gas lift was the better of the two methods of producing this well.

Period	Average oil production	Gas-oil ratio	Operating
	(Bbls. per day)	(Cu. ft. per bbl.)	Status
Nov. 1 to Nov. 8........	387	307	On pump
Mar. 2 to Mar. 12.......	460	202	On gas lift
May 20 to May 31.......	286	325	On pump

Figure 16 is a production graph of a well in the Hubbard field, Okla. This well flowed naturally under pressure control applied by means of flow beans until April 1, when the gas lift without pressure control of any kind was installed. Oil and gas production increased materially upon the installation of the gas lift and the gas-oil ratio increased from an average of 400 to about 1,300. On June 10 pressure control by means of flow beans was applied, and it was continued throughout the period shown by the data. During the period of pressure control, the pressure and volume of inlet gas was varied frequently to determine whether or not the well was producing with the minimum gas-oil ratio. Every effort was made to produce the minimum amount of formation gas with each barrel of oil. It may be noted that these efforts, subsequent to July 28, resulted in a decrease in the gas-oil ratio and a consistent gradual increase in the amount of oil produced daily. The results obtained at this well prove conclusively that pressure control on gas lift wells is a practical oil conservation measure.

Figure 17 gives operating data on another well in the Hubbard pool. The installation of the gas lift on March 21 had little effect on the gas-oil ratio but did appreciably increase the average daily oil production. During the well's flowing life, and while on the gas lift up to July 7, the flow from the well was through 5 3/16-inch casing. Between July 7 and 10 tubing was installed, and from then on the flow from the well was through the 2½-inch tubing. The gas-oil ratio decreased after the installation of tubing, and at the same time the decline in oil production was arrested.

The results obtained in the Hubbard pool on four wells where pressure control was applied to gas-lift operations showed marked decreases in the gas-oil ratio at three wells, and in at least two of the wells the decrease was attributed directly to the use of pressure control.

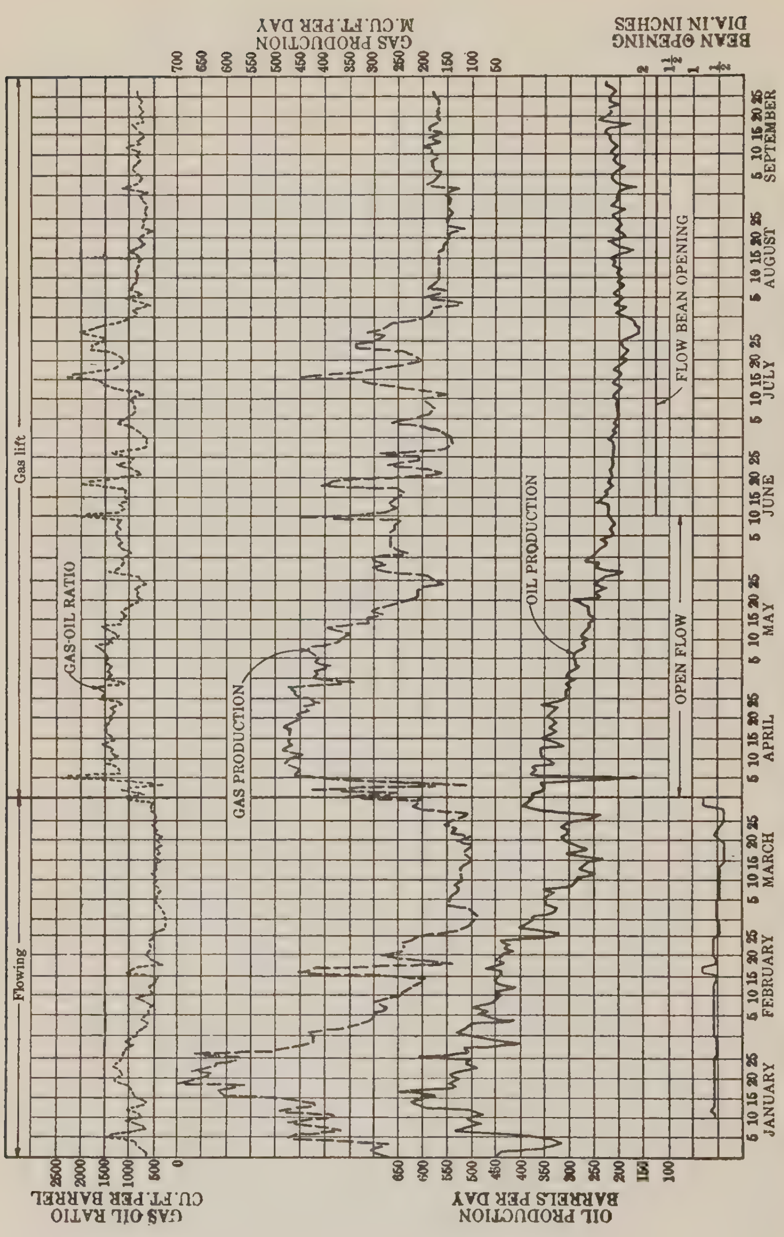

FIGURE 16.—Production graph of a well in the Hubbard field, Okla., which flowed naturally under pressure control for three months and then produced for a time under the stimulus of gas lift without pressure control, followed by gas lift with pressure control by means of flow beans

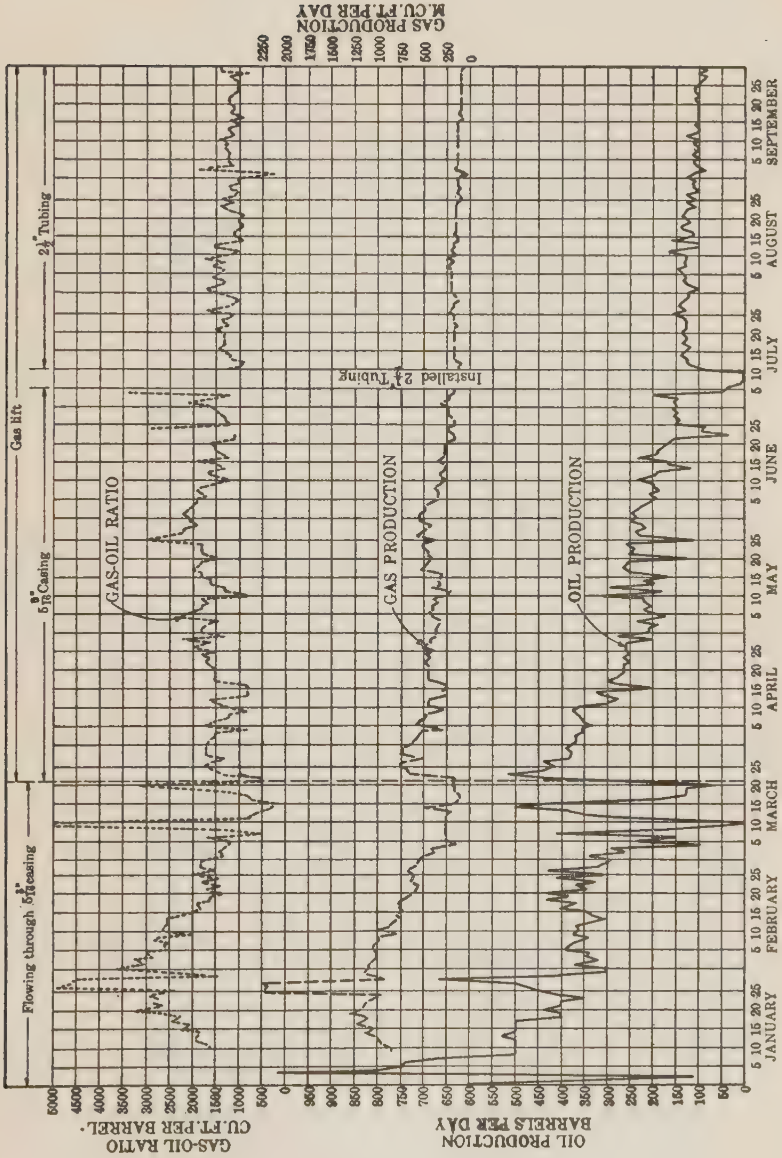

FIGURE 17.—Production graph of a well in the Hubbard field, Okla., covering the flowing life of the well and six months' production by gas lift

EFFECT OF GAS LIFT ON RATE OF PRODUCTION DECLINE

The size range of wells in which the gas lift has a beneficial influence has been investigated; comparison of the average rate of decline of a group of wells on the gas lift in the Huntington Beach Town Lot area, Calif., with that of a similar group made up of wells flowing naturally at first and later on the pump disclosed the following conditions:

1. Wells producing over 300 barrels a day on the gas lift showed a markedly better sustained production than wells similarly located which are flowing naturally or are on the pump.
2. Wells producing between 200 and 300 barrels per day show a slightly better sustained production due to the gas lift, while in wells producing less than 200 barrels a day the rate of decline of the gas-lift wells is more rapid than that of wells on the pump.

The production range covered in the preceding comparison includes the normal flowing period of the life of the average well, the transitionary stage between flowing and pumping stages, and a portion of the pumping history. The results seem to indicate that during the time that the well would normally be flowing, the gas lift, by decreasing the gas-oil ratio and therefore increasing the recovery efficiency, would lower the production decline rate. This benefit becomes less and less marked as the flowing phase of the range changes to the transitionary stage, and finally the pumping well with its more efficient gas-oil ratio shows a better sustained production from 175 barrels down than the wells of the same size on the gas lift.

The comparison cited above suggests that, at least as far as the Huntington Beach Town Lot area is concerned, the use of the gas lift is inadvisable on wells producing less than about 200 barrels a day—or, in other words, from the time that the fluid production can be handled with a standard oil-well pump. This range of course varies in other fields and probably in many individual wells in a single field. The advisability of pumping at this time is further empha-

sized by cost data available which show the lifting cost per barrel to be materially lower for small wells on the pump than on gas lift.

There are many wells, however, which, because of the crookedness of the holes, or their small diameter and great depth, cannot be pumped by rods. Many thousands of barrels of oil have been recovered by the gas lift from wells in the United States that could not have been produced otherwise. The mechanical condition of the well, therefore, is in some instances a factor upon which the producing method must be based. Even though lifting costs, by using compressed gas or air, exceed the pumping costs in wells of similar depth and productivity, it may still be more economical in the long run to produce certain wells at a higher lifting cost per barrel than to abandon the wells because they are too deep or crooked to be pumped with tubing and rods.

ADJUSTING AND MAINTAINING BACK PRESSURE ON PUMPING WELLS

The effective back pressure on the producing formations may be controlled on pumping wells in the same manner as in flowing wells, with the additional assistance of varying the column of fluid in a well by controlling the depth of the pump, the speed and length of the pumping stroke, and the type of equipment used.

When a well approaches the end of its flowing life the gas-oil ratio has usually reached a higher figure than is necessary to recover oil from the sands. This is due to the gradually increased resistance underground and to the relatively inefficient action of the gas in raising the oil through the tubing. When the well is put on the pump, almost all of the energy required to raise the oil to the surface is furnished by means of the rods; less formation energy, and therefore less gas, is required to move a barrel of oil from the sands to the flow tanks on surface.

As a rule, as wells become older gas-oil ratios increase because of the lower effective expansion ratio and the increased opportunity for by-passing of gas in the partly depleted sands. Installing the gas lift or a bean pump in a flowing well, or making other changes in producing methods, may decrease gas-oil ratios temporarily, but after the effect of the change has worn off the ratios usually increase again. For example, prior to going on the pump, the gas-oil ratio in a well in the Huntington Beach field, Calif., had averaged about 500 cubic feet per barrel for some months. Immediately preceding the time it ceased flowing the gas-oil ratio was 580. After being placed on the pump the gas-oil ratio fell to 300, and in six months was down to 216. From then on the ratio gradually increased until measurements taken four months later showed gas-oil ratios of over 300 cubic feet per barrel.

Similar results are shown by wells in the Buena Vista Hills, San Joaquin Valley, Calif., where one well while flowing by heads was making as high as 5,000 cubic feet of gas per barrel of oil. When the well was placed on the pump, oil production doubled, and the gas-oil ratio decreased to 300 cubic feet per barrel.

A well in the Brea field, Calif., flowed naturally with a gas-oil ratio of 2,700 cubic feet per barrel, and when placed on the pump the ratio fell to less than 400 cubic feet per barrel. After several months of pumping, the tubing was lowered and a gas anchor installed. During the 18 months following this change the gas-oil ratios averaged 323 cubic feet per barrel.

A well in the Chalk pool, Howard County, Tex. (Well E, Table 6), flowed naturally with a gas-oil ratio of 29,800 cubic feet per barrel; when placed on the pump only 374 cubic feet of gas accompanied a barrel of oil to the surface—a reduction in gas-oil ratio of 99 per cent. Table 6 shows the results of work done by one operator in the Chalk pool on the reduction of gas-oil ratios in pumping wells. Two

TABLE 6.—GAS-OIL RATIOS BEFORE AND AFTER OPERATING CHANGES WERE MADE IN FIVE PUMPING WELLS IN THE CHALK POOL, HOWARD COUNTY, TEX.

Well	Test No.	Natural gas-oil ratio, cu. ft. per bbl.	Pumping gas-oil ratio, cu. ft. per bbl.	Decrease in gas-oil ratio, cu. ft. per bbl.	Status of operating change	Gas-oil ratio after operating change, cu. ft. per bbl.
A	1	1,640	1,190	450	Tubing lowered 24 feet	834
B	1	3,710	5,210	1,500 *	Tubing raised 20 feet	3,040
	2				Tubing raised 188 feet	2,600
C	1	....	350	....	Installed liner with bottom foot perforated	70
D	1	....	1,225	....	Installed liner with bottom foot perforated	680
	2	....	1,225	....	No liner	1,160
	3	....	1,225	....	Tubing raised 24 feet	605
E	1	29,800	374	29,426	Changed from flowing to pumping	

* Increase.

methods were used in these tests to effect increases in back pressure. In some wells the tubing level was raised, thereby causing the column of fluid in the well to exert greater pressure on the producing formation; and in others, perforation points in the liners were changed. Although changing the liners to put a greater back pressure on the producing sand lowered the gas-oil ratio, the results seem to show that the same results can be obtained more cheaply and more efficiently by raising the tubing level. These tests showed further that unless the " fill-up " curve on a well is available, the only way to determine the best and most efficient point at which to set the tubing is by experimentation. Even then, the tubing level will have to be changed from time to time to meet the changing conditions in the well.

The results obtained in reducing the gas-oil ratio in Well E (Table 6) when this well was changed from a flowing well to the pumping status is an outstanding example of what is sometimes accomplished when high gas-oil ratio wells are placed on the pump.

Wherever tests of any sort are made on oil wells it has been the experience that all wells do not respond similarly to the same changes in operating methods. While it is to be expected that lowering the tubing in a pumping well should increase the gas-oil ratio, since the effective back pressure in a pumping well is decreased when tubing is lowered, Well A, Table 6, gave a lower gas-oil ratio after lowering the tubing.

In the Turberville pool, Archer County, Tex., all attempts at raising the tubing resulted in rapid increases in the gas-oil ratios and a decrease in production. The tubing was raised in the different wells from 10 to 60 feet and always showed the same results. Although it is easy to understand why production decreased, since by raising the tubing additional back pressure was placed on the oil sands, it is not exactly comprehensible just why the gas-oil ratios increased under increased back pressure, unless the effective back

pressures against the sands before raising the tubing were already greater than those yielding minimum gas-oil ratios.

Back pressure experiments conducted in the Dominguez field, Calif., on a small pumping well that had a daily production of 45 barrels of oil and 500,000 cubic feet of gas showed that by holding back pressure on the casing it was possible to produce 10 per cent more oil with 10 per cent less gas. Back pressure was maintained on this well by means of a small flow bean in the casing head, and adjustments in pressure were made by bleeding off the gas. At first this well gave considerable trouble through gas-locking of the pumping valves, but this difficulty was overcome by the installation of a gas anchor and by a change in tubing depth. Although this well was perhaps more gaseous than the majority of pumping wells throughout the oil fields in general, recent experiments have shown that employment of back pressures can effect substantial reductions in gas-oil ratios on less gaseous pumping wells.

The benefits of back pressure control on pumping wells, the methods of regulating back pressures, the difficulties sometimes experienced in applying back pressures on pumping wells, and the methods of overcoming these difficulties have been ably summarized in a report [16] from which the following is quoted:

"There are several thousand pumping wells in the State of California which together produce a large quantity of natural gas. With the exception of a few wells that have been subjected to experimental work, these pumping wells produce without any attempt being made to control their gas production. However, the experimental work which has been carried on indicates that many times very substantial reductions in gas production can be made by proper control

[16] Report prepared by sub-committee to California Operator's General Committee on Gas Conservation, How to Increase Oil Recovery and Conserve Gas in the Field: Chamber of Mines and Oil, Los Angeles, Calif., April, 1928.

of back pressures, and frequently this control can be applied without serious loss in present daily oil production, and with a resultant arrested decline which will be reflected in increased oil recovery.

"Back pressure on a pumping well can be regulated either by means of a tight casing head, making possible the holding of gas pressure on the casing, or by means of adjusting the tubing depth. The tubing depth method of controlling gas-oil ratios may be effective, but it is more difficult to apply than the holding of gas pressure on the casing, because changing tubing depth does not permit the operator to know the exact amount of change in back pressure on the sands. Also, every change in back pressure by this method involves removing the well-head fittings and actually raising or lowering the tubing. Adjustment of back pressure by means of gas pressure in the casing may be obtained simply through the operation of a valve or the use of a flow bean on the blow-off line from the casing head. A pressure gage on the casing gives a direct measurement of the change in back pressure.

"The holding of gas pressure on the casing head frequently causes trouble through gas-locking of the pumping valves, a difficulty which, unless it is detected and overcome, may result in abnormally low oil production, because the pump will not pump the fluid that has entered the well. This causes low daily oil production because of the failure of the pump to lift steadily and because the fluid level will rise and exert additional back pressure on the sands. Experienced production men readily detect gas-locking and correct it by means of gas anchors, by spacing the pump valves, and by other measures. However, unless this gas-locking is detected and corrected, low daily oil production may lead to erroneous conclusions regarding the actual potential production of the well against a given back pressure."

APPLYING BACK PRESSURES TO PUMPING WELLS BY STOPCOCKING

Stopcocking experiments relative to gas production of wells which pump less than 24 hours per day were carried on in the Salt Creek field, Wyo. During the tests, while the wells were not pumping, the gas was shut in the sand, and

the gas plant was permitted to take the gas from the wells only while the wells were pumping. There was a marked decrease in gas-oil ratio and an arrested decline in oil production when the wells were produced by stopcocking. These tests resulted in applying the practice of stopcocking to all short time pumping wells in the field, for arrested decline indicates increase in ultimate production. No actual figures are available showing the amount of decrease in gas

TABLE 7.—DAILY AVERAGE OIL AND GAS PRODUCTION AND CORRESPONDING GAS-OIL RATIOS BEFORE AND AFTER STOPCOCKING FOR 16 LEASES IN THE SALT CREEK FIELD, WYO.

BEFORE STOPCOCKING

Date	Daily average oil production, bbls.	Daily average gas production, M cu. ft.	Gas-oil ratio, cu. ft. per bbl.
June 10	3,710	7,050	1,900
20	3,640	5,800	1,593

AFTER STOPCOCKING

Date	Daily average oil production, bbls.	Daily average gas production, M cu. ft.	Gas-oil ratio, cu. ft. per bbl.
June 30	3,720	5,200	1,397
July 10	3,920	5,000	1,275
20	3,990	5,150	1,290
30	4,000	5,530	1,382

production as a result of field stopcocking, but it is conservatively estimated to be approximately 3,000,000 cubic feet per day.

Table 7 gives the daily average production figures of oil and gas for 16 leases in the Salt Creek field and shows the beneficial effects of stopcocking pumping wells.

Swigart and Bopp[17] concluded after making a series of stopcocking tests on pumping wells in northeastern Osage

[17] Swigart, T. E., and Bopp, C. R., Experiments in the Use of Back Pressures on Oil Wells: Tech. Paper 322, Bureau of Mines, 1924, p. 59.

County, Okla., that " the efficiency of production by stopcocking dropped to about 30 per cent of the efficiency at 50 pounds' pressure because by stopcocking more gas was produced per barrel of oil than by holding 50 pounds' pressure. Therefore, although the present daily oil production was greatly increased by stopcocking, the amount of gas used per barrel of oil was three and one-third times that used per barrel at 50 pounds' pressure. Such practice no doubt would reduce appreciably the total ultimate production that could be obtained by keeping the back pressure on the well near the potential rock pressure."

If stopcocked wells are closely offset by others at low pressure, the formation pressures while the stopcocked wells are off must not become too high or the oil production may suffer and the offset wells may gain. This unfavorable condition may be partly overcome by more frequent producing periods and shorter " closed in " periods.

Stopcocking probably will increase the daily oil production of most pumping wells and in some cases reduce gas-oil ratios. Because gas-oil ratios are not always decreased, stopcocking may not be an efficient producing method in every pumping well. Therefore, experimentation on individual wells is necessary to determine the efficiency of this method.

Although the following data on intermittent pumping of wells in the Cook pool, Shackelford County, Tex., do not relate strictly to stopcocking, there nevertheless is some similarity between the intermittent pumping method used on a certain lease in that pool and stopcocking (except that the gas was not confined) to justify mentioning it at this time.

In an attempt to prorate production on a small lease in the Cook pool, a pumping schedule was adopted which limited the pumping of wells to 25 per cent of the time. No restriction was placed on gas production, so that gas was taken continuously from the wells during both pumping and

shutdown periods. Table 8 shows the data obtained from one month's operation under these conditions.

It should be noted that 821,000 cubic feet of gas were taken from the wells while they were off production. This volume of gas bubbled through the oil that had accumulated in the well and did very little work in bringing oil to the well. Enough gas was taken from the wells during the time that the wells were idle to bring approximately 700 barrels of

TABLE 8.—ONE MONTH'S OIL AND GAS PRODUCTION OF A LEASE IN THE COOK POOL, SHACKELFORD COUNTY, TEX., SHOWING INCREASE IN GAS-OIL RATIO DUE TO PUMPING THE WELLS ONLY 25 PER CENT OF THE TIME

	Total oil production, barrels	Total gas production, cubic feet	Gas-oil ratio, cu. ft. per bbl.	Remarks
On production ...	295	340,000	1,180	Pumping
Off production ...	None	821,000	....	Gas to gasoline plant
Total, 31 days...	295	1,161,000	3,940	

oil to the wells, with a gas-oil ratio of 1,180. In other words, 700 barrels of oil were robbed of the gas necessary to expel the oil from the sand; lease production approximating 995 barrels might have been produced during the month with the same amount of gas that under the proration agreement allowed the recovery of but 295 barrels. From the standpoint of recovery efficiency, it is evident that the wells on this lease should have been pumped a greater percentage of the time, and that the proration schedule in effect was wasteful of gas.

SWABBING

BACK PRESSURE CONTROL INAPPLICABLE

This method of producing oil can hardly be classed as a standard method. Swabbing is resorted to largely as a temporary measure and does not lend itself to the application of pressure control or to gas conservation in the production of oil. No information is available concerning any attempt

to apply pressure control to swabbing wells; the very nature of swabbing operations would make such an attempt futile.

The present practice of swabbing through casing is wasteful of gas and, moreover, if continued for any length of time will " line cut " and otherwise damage the well casing and liners. If swabbing is necessary it should be confined to wells that will not flow naturally through a minimum permissible size of tubing. Gas lift is usually adaptable to wells of this kind and is a much more satisfactory production method.

VACUUM AND ITS EFFECT ON OIL AND GAS PRODUCTION

Vacuum is applied to oil wells, in which gas pressure has become nearly exhausted, by connecting the casing-head gas line to the suction line of a vacuum pump. The discharge from the vacuum pump is usually connected into a gas-distributing system which conveys the gas to a plant where the gasoline fractions are removed from the gas by absorption and compression processes.

Several interesting tests were conducted in the Salt Creek field, Wyo., in an effort to determine the effect of vacuum on oil and gas production. Atmospheric pressure and vacuums of 4 inches, 10 inches, and 15 inches of mercury were held on the wells during the tests. The duration of each test was one week—by far too short a period to prove conclusively what effect vacuum has on oil and gas production. During one series of tests the wells were so tubed that the producing sand was always covered with oil. Later, similar tests were made with the pump located below the top of the sand so that the sand was " uncovered."

An increase in gasoline content of approximately 0.5 gallon per thousand cubic feet of gas was obtained with increase in vacuum from atmospheric pressure to 15 inches of mercury. The gasoline content of the gas taken from the well while the pump was located below the top of the sand

was approximately 50 per cent higher than in those tests in which the sand was maintained " flooded." The gravity of the crude dropped in both series of tests as vacuum was increased, and was approximately 0.5° A. P. I. lower at vacuum of 15 inches of mercury than at atmospheric pressure. There was no appreciable increase in oil and gas production when the pump was located above the top of the producing sand. However, when the face of the producing formation was exposed, there was a decided increase in the volume of gas produced with increase in vacuum, but no appreciable difference in the amount of oil production.

In the Second Wall Creek sand in the Salt Creek field on the crest of the structure there is an area which has a high gas-oil ratio resulting apparently from the migration of gas toward the high portion of the dome. Surrounding this area and between it and the edge of the production area there is an intermediate zone where the average production per well is comparatively large and the gas-oil ratio is low. The yield of oil per acre in this intermediate zone has been above the average of the field. There is, however, one area in this zone on the flank of the structure, where the oil production per well is very low and the gas-oil ratio is the highest in the field. Nine leases in this area have been subjected to vacuum continuously since January, 1925; Figure 18 shows the average daily production of oil and gas per lease and the corresponding average gas-oil ratio for monthly periods from January, 1924, to the latter part of 1927.

At the start vacuum apparently arrested the rate of decline of oil production. The flattening of the oil-production curve, however, was only temporary, and beginning in July, 1925, there was a decided decline in the oil-production rate. Several theories have been advanced regarding the cause of this temporary arrested decline. The most logical reason seems to be that vacuum caused a temporary increase in oil production, and when later the gas-oil ratio increased, the gas channeled and by-passed the oil in the sand. After

channeling started, the gas came to the well without bringing its full load of oil. As the working barrels in most wells were located below the top of the producing sand, the upper part of the sand was comparatively dry and afforded an unrestricted passage through which the gas traveled to the well.

Although there are no definite records on the amounts of

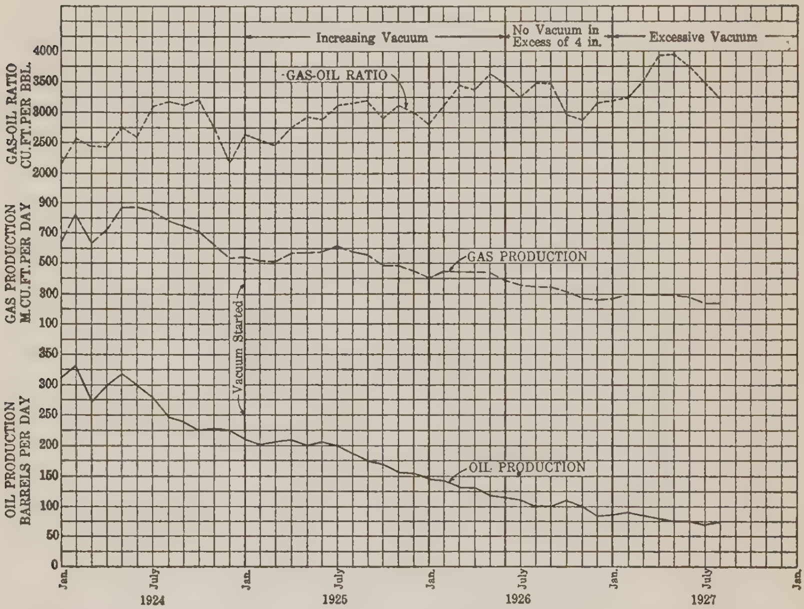

FIGURE 18.—Production graph illustrating the effect of vacuum on oil and gas production on certain leases in the Salt Creek field, Wyo.

vacuum carried on the casing heads, it is known that between January, 1925, and May, 1926, vacuum was increasing. Between June, 1926, and December, 1926, no vacuum in excess of 4 inches of mercury was held on any of the wells, but subsequent to January 1, 1927, excessive vacuum was maintained in the wells.

Figure 18 shows that as vacuum increased the gas-oil ratio increased materially until about the middle of 1926, when there was a reduction in the amount of vacuum held

on the casing heads. The gas-oil ratio declined during the period in which no vacuum in excess of 4 inches of mercury was maintained in the wells, and increased again when the vacuum became excessive.

It is interesting to note that the gas production dropped to a low point in the winter of 1926 and 1927, increased during the early part of 1927, and then dropped to a new low point during August, 1927, when tests indicated that a higher vacuum was being maintained at the casing heads than six months earlier. It is evident from the curves that there has been a decided increase in the gas-oil ratios as a result of the application of vacuum, and that there may have been a decline in oil production in excess of that which would have occurred in the event vacuum had not been applied.

Practical operations and experiments have led operators in the Rocky Mountain region to conclude that vacuum is detrimental to efficient production of oil when the fluid level in the wells is below the top of the productive sand. In general, operators found that vacuum is accompanied by:

1. Increase of gas-oil ratio.
2. Increase of gasoline content of the gas produced.
3. Decrease in the A. P. I. gravity of the oil produced.
4. Possible temporary increase in oil production followed by increase in rate of decline, resulting in a possible lessened ultimate oil production.

Inasmuch as oil flows from oil-sand reservoirs to wells chiefly because of differential pressures—in other words the flow is due to the expansion and movement of the gas associated with oil—repressuring where practicable is much to be preferred over vacuum. Both repressuring and vacuum increase the differential pressure between the reservoir and the well and therefore are a stimulus to wells which drain reservoirs of very low gas pressure. The greatest possible increase in differential pressure by vacuum is approximately 13.5 pounds per square inch (representing a vacuum

of approximately 28 inches of mercury); whereas differential pressures of several hundred pounds per square inch can be obtained by repressuring. This fact has caused certain operators in some of the old fields in the Mid-Continent to convert their vacuum plants into repressuring plants, after years of vacuum application to their properties.

Although repressuring is to be recommended over vacuum in most fields, there are times when vacuum has an application that is not open to repressuring. In closely drilled town-lot areas, for example, where well and royalty ownerships are widely scattered, it may be impossible to affect a satisfactory coöperative plan or unit method of operation which would permit and insure equitable results from repressuring. Frequently the abandonment of wells in town-lot areas can be delayed, and additional returns of investment are secured to the operators by the use of vacuum. Considering that the field is almost ready for abandonment anyway, the increased gas and gasoline production which usually accompanies the application of vacuum may earn a substantial profit for the operator even though the oil production is small or temporary. Also, considering that the repressuring is impracticable and the field is ready for abandonment, vacuum is justified if it will further win natural resources from the ground.

Thus, while vacuum pumping is a production method which cannot be recommended for general application, and moreover cannot be expected to have the beneficial effects on production of repressuring, yet it has a specialized field of use which must be recognized.

EFFECT OF SHOOTING WELLS ON GAS AND OIL PRODUCTION

The practice of "shooting" oil wells is confined largely to wells drilled into and producing from "tight" formations such as hard, close-grained sandstones and limestones.

Wells are occasionally shot to overcome mechanical difficulties but more frequently to stimulate the production of oil.

With ordinary care a shot may be exploded so as to accomplish the desired result without damage to the well or to the producing formation, but this necessitates careful measurement, accurate logging of the formations, and care in judging the amount of explosive used. When a sand carrying a large volume of gas lies immediately above an oil sand, a carelessly placed shot exploded too high in the hole will shatter the gas sand and tend to increase the gas volume with consequent waste of gas and loss of energy which, if properly conserved, might otherwise have been useful in flowing the well. The same condition might obtain if there were a relatively thin shale parting between the oil and gas sands. In a similar manner a badly placed shot might shatter the cap rock above the gas sand and a considerable amount of dissipation of gas volume and energy would follow. The shattering of cap rock is a danger of no small moment. If the cap rock is shattered by a shot or breaks are made in it, permitting gas and oil to escape from the sand or permitting water to enter the sand from above, the underground losses may be tremendous. The shattering of formations underlying gas and oil measures when shots have been placed too low have also frequently permitted water to enter the producing sands, necessitating difficult "plugging jobs" to shut off the water.

Waste of gas due to improperly placed shots may be eliminated largely by careful attention to the following factors:

1. Accurate measurements of well depth during drilling, particularly through the producing formations.
2. Correct logging of formations.
3. Careful attention to the size of shots and their correct placement.

Figure 19 is a segment of the production graph of a well in the Garber field, Okla., giving the oil and gas production of the well before and after shooting. It may be noted that

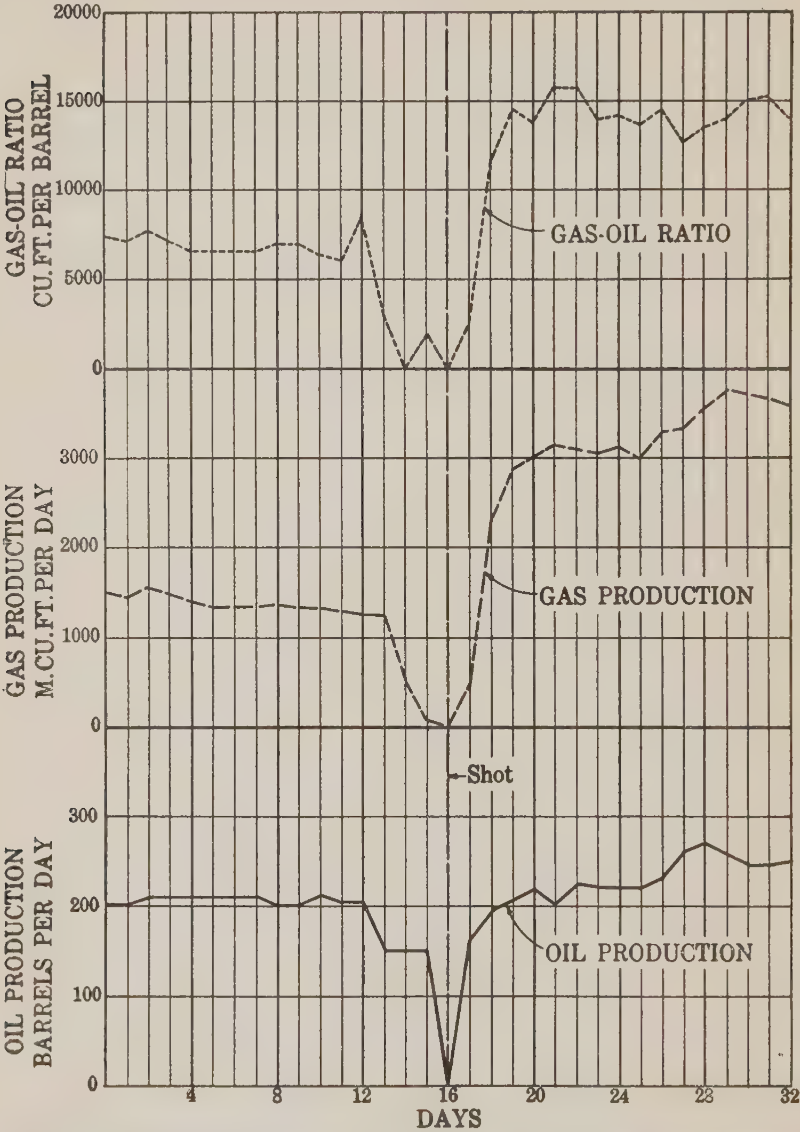

FIGURE 19.—Effect of shooting a well producing from a high-pressure gas-oil sand in the Garber field, Okla. Note that the gas-oil ratio increased materially after shooting

shooting not only increased the oil production but materially increased the gas-oil ratio, chiefly because of the greatly increased gas production and the slightly increased oil production.

Figure 20 shows the effect of shooting a pumping well in the Burbank field, Okla. The rate of increase of the gas-oil ratio was downward after the shot, whereas previous to

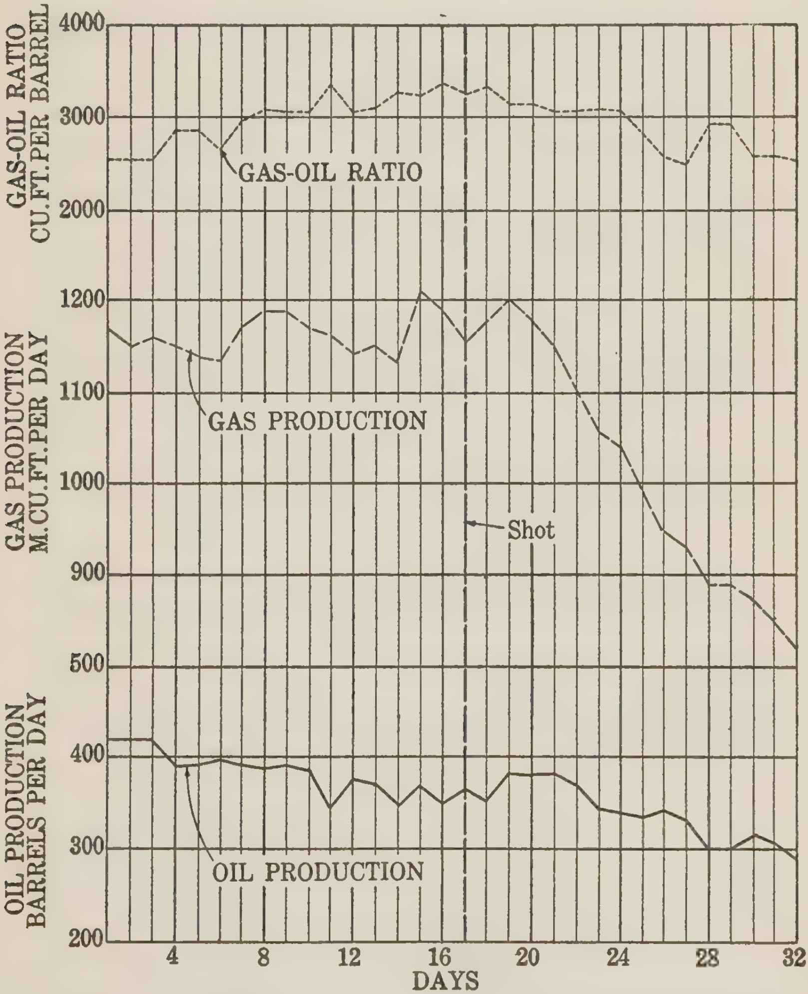

FIGURE 20.—Production data before and after shooting a pumping well in the Burbank field, Okla.

shooting it was increasing almost uniformly at the rate of approximately 200 cubic feet per barrel per month. Evidently shooting had no effect on the oil production in this well, but it did arrest the upward movement of the gas-oil ratio and even caused it to decline.

Attempting to control gas-oil ratios or to get a better one by shooting a well is trusting too much to luck. Where wells have been shot and gas-oil ratios lowered, the reduced ratios were due more likely to increased oil production than to any change underground that might have caused the gas to do more work in bringing oil to the wells.

In other words, the consensus of opinion of production men is that shooting is a method which may increase oil production, but any change that may occur in gas-oil ratios subsequent to shooting wells is usually entirely accidental and could seldom have been foreseen. Therefore, although shooting is an accepted method of stimulating oil production in certain wells, it cannot be considered of value as a means for making definite changes in gas-oil ratios.

EFFECT OF SHUTTING IN WELLS ON FUTURE PRODUCTION

Several properties in the San Joaquin Valley and other fields in California have been shut in and opened up at various times since 1909. Some of these properties have been shut in for as long a period as two years, and the production records afford an opportunity for studying the effects of shut-in periods on subsequent and ultimate production.

Figure 21 is a production curve of a property in the Coalinga field, Calif. This curve shows that the property was shut down from July, 1922, to February, 1924, a period of 22 months. From an extension of the normal production decline curve, the production lost during the shutdown period is estimated as 244,000 barrels. When the section was opened up in February, 1924, monthly oil production

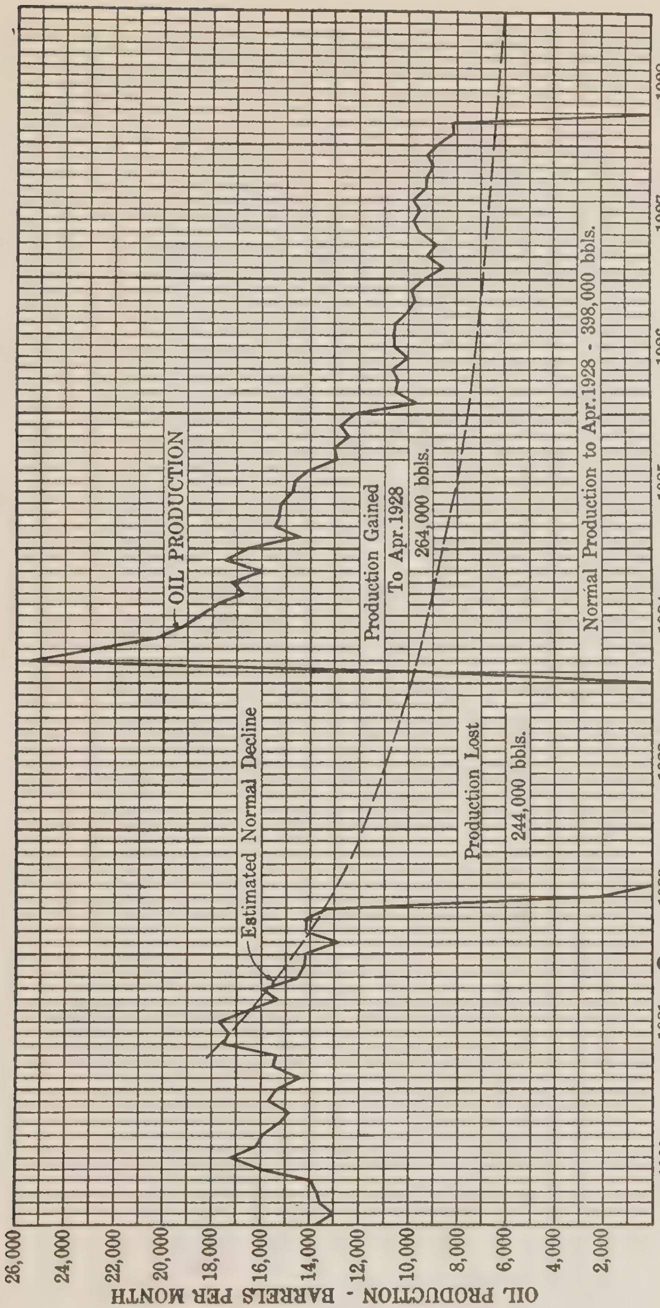

FIGURE 21.—Production curve of a property in the Coalinga field, Calif., which was shut down for 22 months in 1922 and 1923. The curve shows that production lost during the shutdown was recovered in less than four years after the property was opened up

was greater than before the shut-in period, and it is estimated that up to April, 1928, when the property was again shut in, the gain in production was 264,000 barrels over the estimated normal production.

It is apparent from the production graph (fig. 21) that the 22 months' shutdown did not affect ultimate oil production adversely. In fact, 20,000 more barrels of oil was produced up to April, 1928, than was expected on the basis of the property's estimated decline curve. Moreover, when the property was again shut down in 1928 because of overproduction of certain grades of oil in California, oil production the month before the shutdown was still almost 2,000 barrels a month greater than it would have been according to the normal decline curve of this and other properties in the Coalinga field.

The following conclusions have been summarized with regard to the history of the shutdown in the fields of Kern and Fresno Counties, Calif., during 1922-1924:

(1) Considering a structure or field as a whole, the ultimate production was probably not decreased. On some of the leases a large part of the oil which would have been produced was recovered during the months following the shutdown, one lease showing such an increase in production as to recover completely the deferred production less than two years after being opened up. The production graph of this lease is shown in Figure 22.

(2) Structural location had a decided effect upon the production of the several properties, particularly where the gas pressure was largely exhausted and gravity played an important part in the movement of oil into the well. Properties on top of the structure may suffer by drainage. This fact is shown clearly on Figure 23, which is a production graph of a property in one of the San Joaquin Valley fields, Calif. Properties close to edge water may benefit from the pressure caused by the encroaching waters, but oil production may be lost in some of the edge wells. This effect was

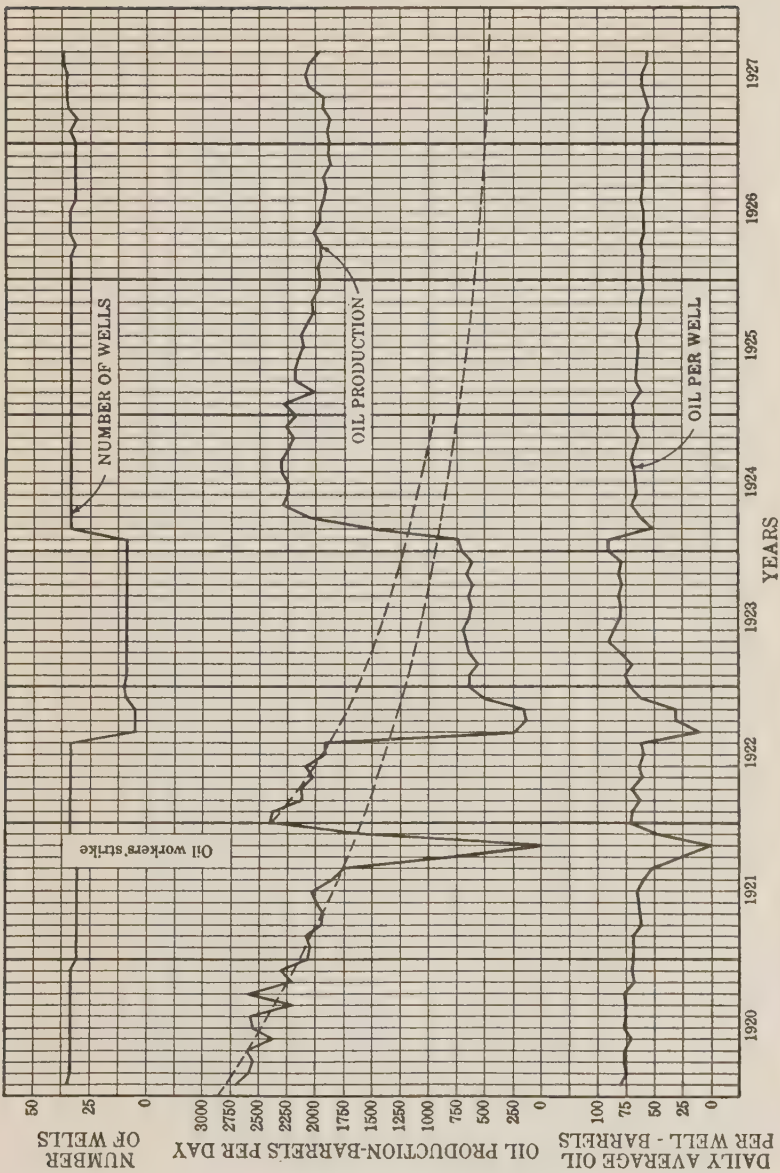

FIGURE 22.—Production graph of a property in the San Joaquin Valley, Calif., showing effect on future production of shutting in wells

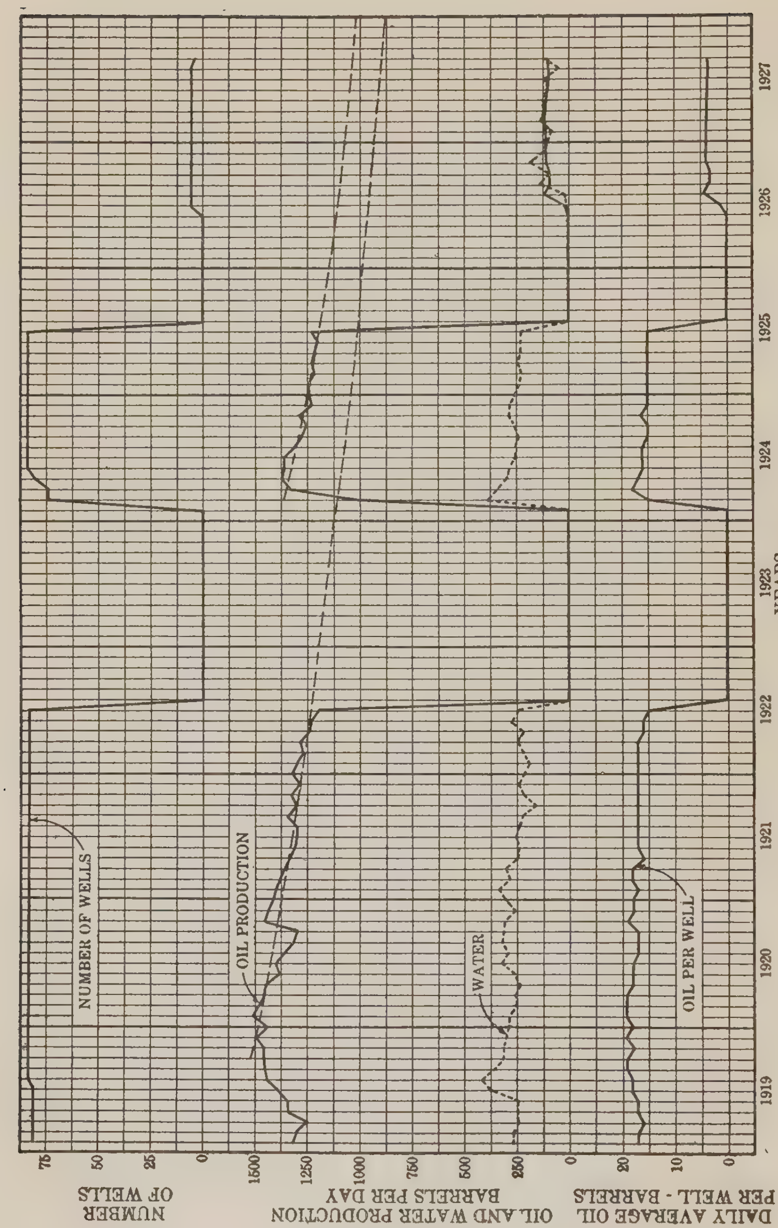

FIGURE 23.—Production graph of a property in one of the San Joaquin Valley fields, Calif., showing effect on future production of shutting in wells on a property where the gas pressure is largely exhausted

evidenced on the property whose production graph is given in Figure 24.

(3) The evidence cited indicates that any general shutdown should be coöperative with adjustments for changes in production resulting from unusually favorable or unfavorable location of the structure. Wells located near the edge-water line or already producing large quantities of

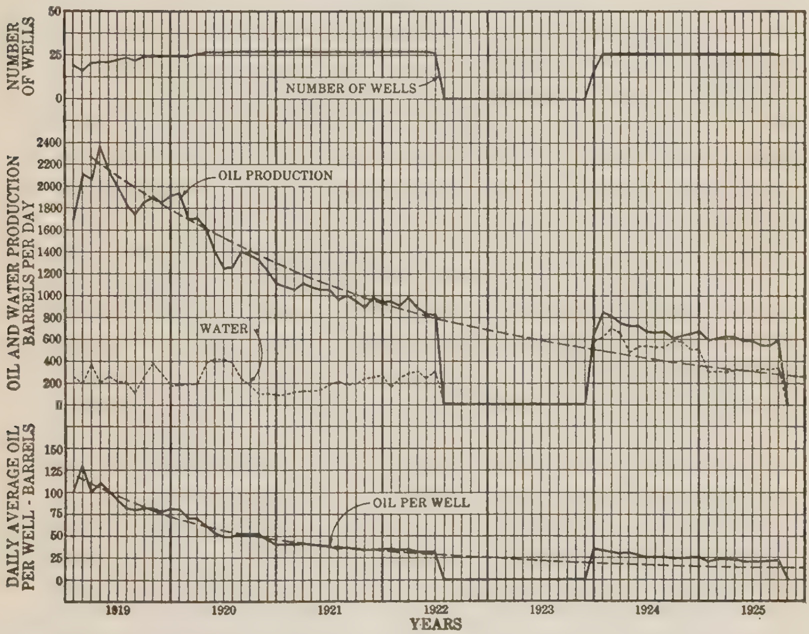

FIGURE 24.—Production graph of a property in the San Joaquin Valley, Calif., showing effect on future production of shutting in wells close to the edge-water line

water may necessarily be left out of any general shutdown if it is believed that their production will be destroyed entirely by a shutdown.

Evidence from the shutdown history of certain wells in the Torrance field, Calif., shows conclusively that small areas, in fields where gas is still the principal producing factor and especially where adjacent properties continue to produce, probably never recover deferred oil production

due to being shut in. Figure 25 shows the production graph of one property in the Torrance field in southern California on which the wells, after a shutdown, came back practically at the point on the oil decline curve which they would be expected to have reached had the property never been shut down. This indicates a total loss of the production for the interval of the shutdown.

EFFECT OF SHUTDOWN ON GAS-OIL RATIOS

Three curves have been prepared, each representing the producing history of a different property in the southern California fields which was shut in for a considerable period at one time or another. These properties have been classified as follows:

(1) A property comprising an entire field which was shut down for a certain period and then opened up. The daily average production of this property before and after the shutdown is shown on Figure 26.
(2) A property which was partly shut down and which was offset by other properties which were not shut in (fig. 27).
(3) A property which was entirely shut down and which was offset on three sides by properties which were not shut down (fig. 25).

A study of the curves (figs. 25, 26, and 27) reveals the fact that after the shutdown the gas-oil ratio was less than it was prior to the shutdown period. The redution in gas-oil ratio is believed to be due to a partial restoration, during the shutdown, of the pressure and oil content of the portion of the sands nearest the wells, with an accompanying reduction of depleted sand channels through which the gas readily by-passed. As conditions in the sands, such as existed prior to the shutdown, are gradually restored, the gas-oil ratio again will increase and approach its original value. Thereafter the gas-oil ratio will continue to increase at a rate depending upon operating methods. The relative magnitude of the changes in gas-oil ratios on the properties shut down and offset by properties which were not shut down shows the effect of offset production.

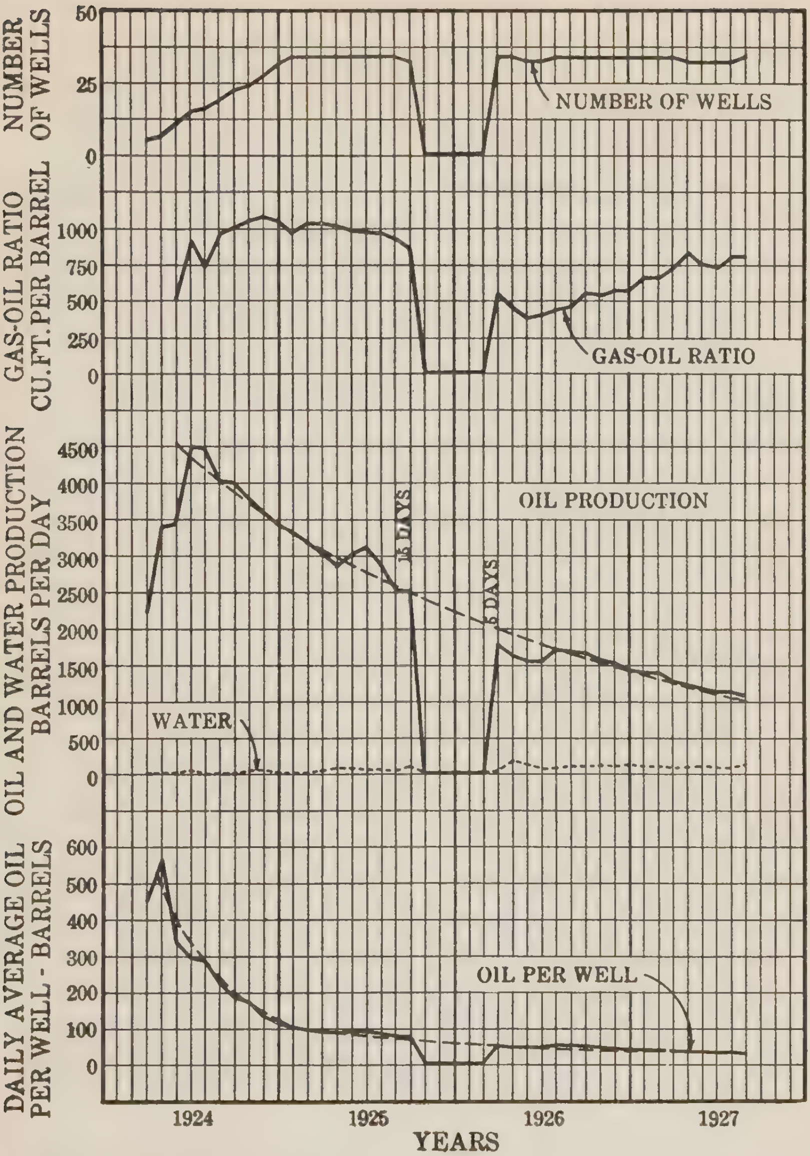

FIGURE 25.—Production graph of a property in the Torrance field, Calif., showing effect on future production of shutting in wells in small areas where gas is still the principal producing factor. This property was offset on three sides by properties which were not shut down

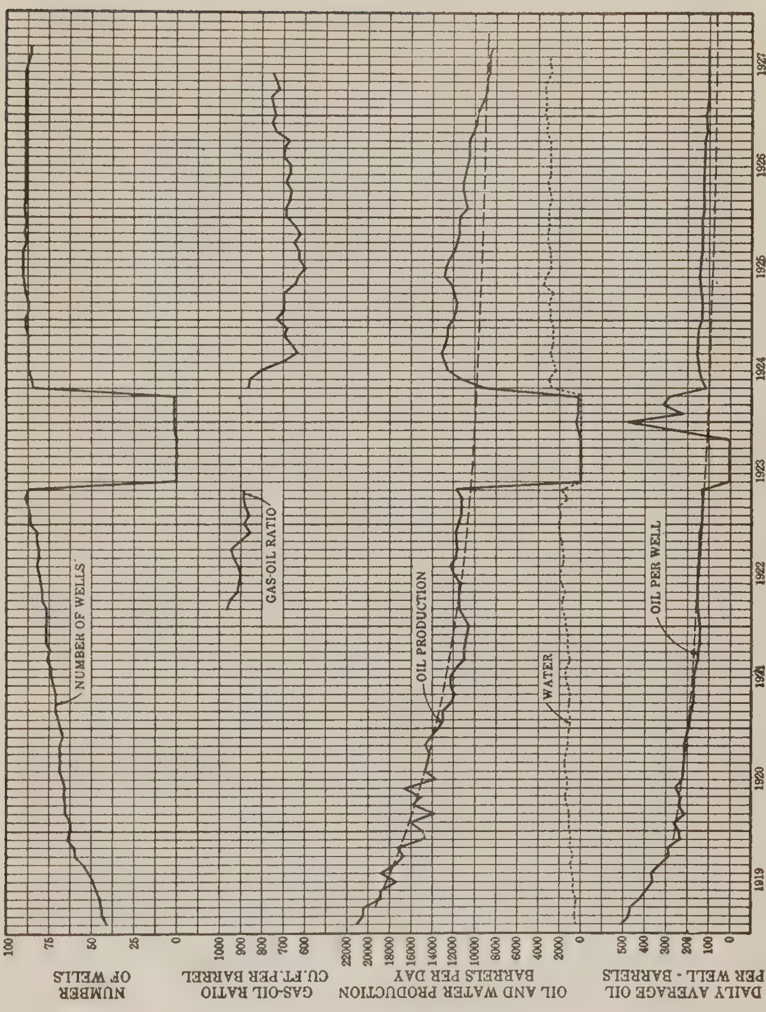

FIGURE 26.—Production graph of an entire field in southern California which was shut down for a certain period and then opened up

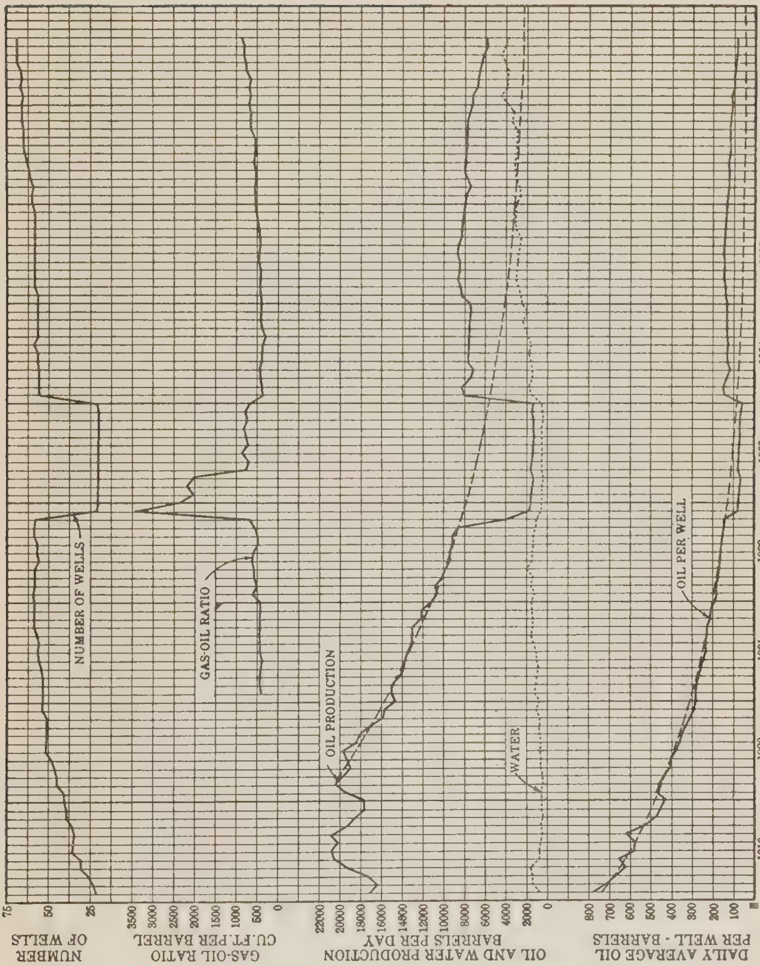

FIGURE 27.—Production graph of a property in southern California which was partly shut down and was offset by other properties which were not shut in

STIMULATING PRODUCTION BY INJECTING GAS INTO OIL SANDS

GENERAL REMARKS

The injection of gas or air into oil sands artificially supplements the energy necessary to move the oil through the sands to the wells. Since it is seldom possible in field practice to produce oil with production efficiencies that even approach 100 per cent, gas injection compensates to a degree for some of the harmful effects of producing oil with high recovery gas-oil ratios.

The practice of stimulating production from oil wells and increasing the ultimate recovery of oil from reservoir sands by forcing a gaseous medium through the oil sand was started in southeastern Ohio in 1911.[18] The original details of the process were worked out by Orton C. Dunn and Harvey E. Smith, and credit is due them for demonstrating the practicability of the process and for bringing it into successful use.

At first, air was injected into the reservoir sands to force oil into surrounding wells, but the trend of recent practice is to reintroduce natural gas into the partly depleted sands. It is only where natural gas is scarce that air is used. There are certain advantages in the use of natural gas as a repressuring medium. Natural gas, because of its solubility in petroleum (see Solubility of Gases in Crude Oils, p. 190 and following), reduces the viscosity of the oil in the sands. Less energy is required to drive a low-viscosity oil through sand than is required to force an oil of high viscosity through the same sand, when other conditions are equal. Although air in true solution in petroleum, if used as a repressuring medium, would be expected to decrease the viscosity, it has been found by different investigators that air tends to oxidize some oils, resulting in an increase in viscosity. In some fields and with certain oils, residue is left in the sands which

[18] Lewis, J. O., Methods for Increasing the Recovery from Oil Sands: Bureau of Mines Bull. 148, 1917, 122 pp.

tends to clog the pores when air is used, and in some wells the use of air hastens corrosion of casing and tubing, probably as a result of oxygen brought into contact with moisture. Also under certain conditions, air introduced into reservoir sands may form explosive mixtures and render the gas produced unsuitable for fuel.

Although natural gas has certain advantages over air as a repressuring medium in some fields, there are many areas where air is used in repressuring operations because gas is not available in sufficient quantities or at a low cost. Many operators in the Pennsylvania and Mid-Continent oil fields have been repressuring oil sands with air, and increased oil recoveries are reported. Air is considered by some engineers to be better than gas for air drive purposes because air does not go into solution in oil as readily as gas. Air is only about one-fifth as soluble in oil as natural gas (see fig. 35), and some engineers believe that the air has " piston effect " on the oil in the reservoir sands which drives the oil to the producing wells at a more rapid rate than is possible with gas. Experimentation in the laboratory and in the field must be extended to a considerable degree before definite criteria with reference to the exact propulsive effects of different repressuring media can be established.

Productive oil measures usually have extreme variations in porosity and texture, both from layer to layer and from one locality to another in the same layer. Many streaks of porous sand, which are the more productive in an oil zone, usually are thin and lenticular and do not extend from well to well. These conditions are not conducive to a uniform spreading of injected gas, and the gas drive from a particular well may therefore assist only one or two of the surrounding producing wells or only part of the sand layers drained by each nearby well.

The possible undesirable effects of the natural underground conditions are aggravated in thick zone fields of California where the sands have been largely depleted by

natural production methods. Certain layers of coarse, open-textured sands, which undoubtedly yielded the largest oil productions during the early life of the fields, probably are flow channels of low resistance which allow by-passing of injected gas from the " key " or injection well to one or more producing wells. This fact was illustrated in the Dominguez field where difficulties were encountered from by-passing of injected gas from key wells to one of the nearby surrounding producing wells. Variations in the amount of injected gas were reflected at once in gas productions of the wells which by-passed the injected gas, and the most severe measures of pressure and production control failed to correct satisfactorily the harmful effects of by-passing.

In the Blake pool, Brown County, Tex., injected gas by-passed through the streaks of more porous sand and traveled horizontally toward the most depleted areas. The placing of additional back pressure on the sands by raising the tubing in pumping wells in an attempt to control the direction of flow of gas was only partly successful. It is natural to expect in most partly depleted fields, and field observations have shown it to be true, that oil sands near the top of thick producing measures have lower pressures than deeper sands in the zone. In California almost all oil sands have contact with edge waters, and it is believed that a gradual and somewhat uniform increase in reservoir pressure occurs from the upper to the lower oil sands in a thick productive zone. These factors limit the application of the gas drive because sands near the top of a thick oil zone are almost always of lower pressure than the deeper sands. For that reason it is probable that all of the injected gas will enter the upper sands of the oil zone without ever entering deeper sands, which frequently are more highly saturated with oil in proportion to gas than upper sands and which therefore would offer the best opportunities for production increases by gas drive. This difficulty has been illustrated on one property in the Dominguez field where it was dis-

covered after several months of gas injection that production increases in surrounding wells were relatively low, the gas apparently passing through the sands that were largely drained of oil. At the same time the gas drive on an adjoining property was yielding production increases because gas injection was taking place at a point low on the flank of the structure where the sands still carried a greater proportion of oil to gas than did these same sands near the top of the adjacent structure.

Similarly, gas injected to the oil zone in the Coalinga field in California by-passed through upper drained sands and was recovered in many wells surrounding the key wells. At this late date in the life of the Coalinga field only the lower part of this zone is productive of oil, and results show that gas introduced to the key well is not entering the productive oil sands in the zone.

In the Mid-Continent, gas drive has been practiced mostly in shallow fields, and it is possible to drill injection or key wells at desirable points in this area by the expediture of relatively small sums of money. In California, gas drive, if successful, will have to be applied in deep, as well as shallow fields. If, because of by-passing or for other reasons, one injection well is not suitable, it is questionable if the great expense which would have to be incurred for a new injection well would be warranted. This consideration, combined with the limitations of property ownerships, has already been an obstacle to the application of gas drive in California, although by this time operators in that State have done considerable work along such lines.

Gas injection, either for increasing oil production or storing gas, will have better chances of commercial application in deep fields which have high initial reservoir pressures, at some time after those fields are partly exhausted. However, in the later periods in the life of a field when reservoir pressures are low enough to permit gas injection at reasonable injection pressures, surplus gas for reintroduction to the formations is frequently not available. If gas is to be in-

jected it either must be purchased from a gas company or else it must represent a reduction in sales of gas of the operator to the gas company, which is equivalent to the purchase of gas. The value of this gas is a further obstacle to the practice of gas injection because there are no data available that permit an estimate of the proportion of injected gas that an operator may ultimately expect to recover. If a field were systematically cased and the oil sands were of reasonable uniformity in porosity, thickness, and extent, an operator might safely conclude that practically all of the gas injected would be recovered. However, underground conditions are usually the reverse of those mentioned, and it is not known what recovery may be safely counted on.

Gas, because of its migratory tendencies, may flow from the injection well of one operator to the property of another. This fact has been observed in several fields and at once points to the conclusion that gas drive or gas storage can only receive general application through the coöperative action of all operators in the particular area where it is being applied. At present the gas drive has been used only on relatively large properties where the danger of migration of the gas to the neighbor's wells is not serious. Experience indicates that there is little uniformity in the direction of flow of injected gas and there is no manner by which the flow or spread may be controlled should it extend past an operator's boundaries, except by the assistance of his neighbor. Also, the direction of spread of the gas cannot be predicted in advance, so that all operators in the immediate area must become parties to the gas injection program.

Although it is conceivable and probable that many operators will coöperate in gas injection programs, still the problem of lessors' rights must be solved before the gas drive can receive wide application in many fields. This problem may be the most troublesome in endeavoring to reach operating agreements for coöperative action, particularly in town-lot areas or in fields of a number of different ownerships.

WHAT GAS INJECTION ACCOMPLISHES

Methods of gas injection into producing sands are still in the pioneer or development stage, but enough information has been obtained to indicate the following:

1. Gas injection gradually builds up pressure in the oil sands and increases pressure differentials between areas adjacent to the injection or key wells and the producing wells. This addition of energy in the form of compressed gas results in driving to wells oil that might otherwise be dependent upon water encroachment and gravity as an expulsive force, and much of which, therefore, might never be recovered.

2. By injecting gas into oil-bearing formations, extraneous energy is supplied which aids the energy contained in the formation gas under pressure to move oil to the well. From the experience in various fields in Texas and California it appears that early injection of extraneous gas may be better than a sudden replacement of gas at a time when the field is almost exhausted by natural production methods, because in the early life of an oil field the sands are less depleted of oil and therefore afford less opportunity for by-passing.

3. Gas injection causes a reduction in the viscosity of the oil in the sands. Laboratory experiments have shown that oil which has absorbed gas under pressure is much less viscous than the same oil at atmospheric pressure. Lower viscosity undoubtedly is an aid to the migration of oil through sands.

4. The injection of gas into oil formations offers a means of storing surplus natural gas at times when markets are not available. It is recognized that part of the benefit derived from the gas drive experiments now being conducted in the Dominguez and Coyote fields in California is that these fields afford a means of storing gas which could not be marketed in the Los Angeles district. On September 1, 1928, approximately 46,000,000 cubic feet of gas a day was

being stored in oil producing formations in nine California fields.

5. The introduction of compressed dry gas to oil-bearing formations, whether for the purpose of increasing oil recovery or storing gas, may be found profitable because of the gasoline which the injected dry gas absorbs from oil remaining in the sands. Upon the exhaustion of an oil field, much oil adheres to the sand grains and would not be recovered within a reasonable length of time by such agencies as water drive and gravity. Any gasoline that can be absorbed from this oil by injected gas represents a gain of a natural resource that otherwise would never be recovered except possibly by mining.

It is apparent that the introduction of gas to oil and gas bearing formations is a procedure that offers several opportunities for success and profit to an oil operator and also is one that becomes a very distinct conservation method. Aside from the possibilities of increasing oil recovery and storing excess gas, the operator may recover enough gasoline from the injected gas to more than pay the cost of injection.

GAS INJECTION METHODS DESCRIBED

By the general term "gas injection" is meant the introduction of gas into the reservoir, generally by the aid of compressors, through injection wells, either wells drilled for the purpose or old wells taken off production and used as "key wells." Under the general heading of gas injection, four distinct purposes and methods of procedure are recognized:

1. Pressure maintenance.
2. Pressure restoration.
3. Gas drive.
4. Gas storage.

Pressure maintenance (1) differs from pressure restoration (2) principally in the time the operation is begun.

Where gas injection is begun at once with the idea of maintaining the reservoir pressure as near its original value as possible, the operation is pressure maintenance; and where it is begun at a later date and carried on either simultaneously with production operations or intermittently with such operations, it is pressure restoration. Probably neither operation ever will be perfect in practice, and both may approach the third type of operation because of mechanical limitations and direct by-passing of the gas through sands already partly depleted.

Gas drive (3) is the injection of gas to drive or carry along mechanically toward the producing wells some of the oil in the partly depleted sand. The emphasis of this method is on the drive rather than on the lowered viscosity and other pressure features of the first two methods. All of the methods have common effects, and the results of each partake of the benefits of the last, which is gas storage (4). Where the demand for gas is seasonal, the summer surplus often can be stored to good advantage in partly depleted oil or gas reservoirs to be drawn upon in times of greater need, at the same time do its part in increasing oil recovery from the sands in which it has been stored.

RESTORING PRESSURE IN OIL SANDS

A study of the results of injecting gas into the oil-producing formations in Texas, Pennsylvania, California, and elsewhere shows in almost every instance that the injection of gas increases both the daily production of oil and the total ultimate expectation of oil. The amount of additional oil recovered in proportion to the amount of gas introduced, however, varies considerably. For example, on one property in the Blake pool, Brown County, Tex., it is estimated that 1 barrel of additional oil is being obtained for each 400 cubic feet of gas injected. On the other hand, in the Powell field in Navarro County, Tex., 1,022 cubic feet of gas are introduced into the producing sands for each barrel of additional oil recovered.

A study of the results of gas injection in the Blake pool in Texas indicates that the ultimate recovery of oil will be increased approximately 31 per cent above that which would have been obtained if no pressure restoration work had been done. Even better results are anticipated in the Turberville pool in Archer County, Tex. Engineers estimate that pressure restoration operations in this field will yield 60 per cent more oil ultimately than normal nonrestoration methods would have recovered.

Repressuring in nine fields in Texas has established the fact that when gas injection first starts, sometimes several months elapse before any appreciable effects are noted in the amount of oil produced by the wells that surround the key or injection wells. Frequently even if there is no increase in production, the normal decline of production is arrested. That the increase in oil production, or the arresting of the normal decline in oil production, was due entirely to the injection of extraneous gas was definitely proved on several properties where oil production declined abruptly when pressure restoration work was temporarily suspended.

BLAKE POOL, TEXAS

In Brown County, Tex., natural gas is being used to restore pressure in the Blake pool, a shallow field of about 1,500 acres producing from a sand averaging about 15 feet in thickness at a depth ranging from 1,150 to 1,200 feet. The Blake pool produced 2,714,000,000 cubic feet of gas from May 1, 1926, to September 1, 1927, of which 20,835,694 cubic feet, or 0.77 per cent, was injected back into the sand. The increase in production due to pressure restoration was 35,947 barrels, or 1 barrel of oil to every 577 cubic feet of gas injected into the producing sand.

Figure 28 shows a block of leases in the north part of the Blake pool. All of the leases shown, with the exception of leases B and C, are owned by one operator. The injection of gas into key well No. 1 was started on January 17, 1927. This well is in the center of four producing wells in the

northeast corner of lease I. It is 1,179 feet deep and penetrates 18 feet of producing sand which is logged as soft and porous. At first the well took 32,400 cubic feet of gas a day at a pressure of 160 pounds per square inch, but this amount decreased almost immediately to 20,000 cubic feet a day at the same pressure. At the end of seven months the injection pressure was down to 60 pounds per square inch.

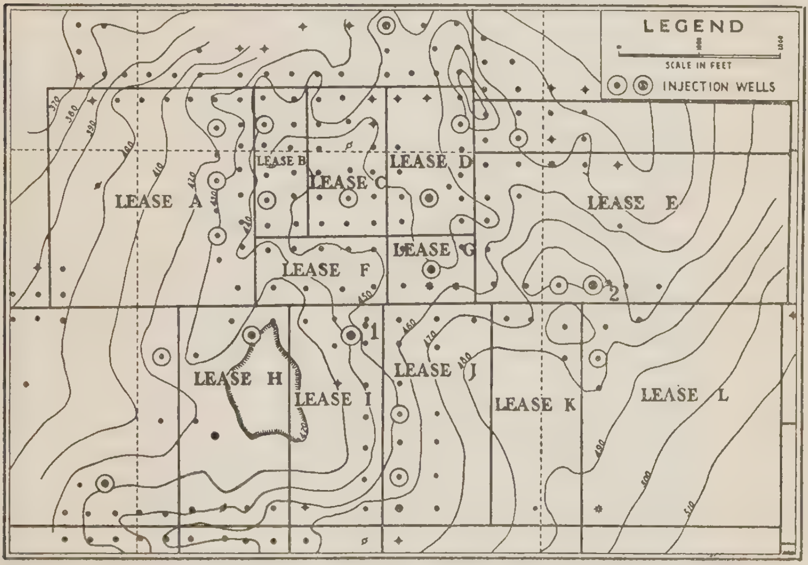

FIGURE 28.—Subsurface contour map of a portion of the Blake pool, Brown County, Tex., showing location of gas injection wells

Soon after pressure restoration started, lease F to the north of the key well began to show increased production. By March 8, 1927, daily oil production had increased from 170 barrels—the amount produced on January 19, 1927—to 304 barrels. During the same period, gas production increased from 106,870 to 296,721 cubic feet a day. At this time, 2,020,445 cubic feet of gas had been injected into the producing sand through key well No. 1, giving an increase of 1 barrel of oil for every 400 cubic feet of gas injected.

A check of the production on leases B and C showed that daily oil production on lease B had increased from 200 to

240 barrels, and from 200 to 335 barrels on lease C. Since these two leases are not owned by the operator who was restoring pressure in that section of the pool, it was to his interest to prevent oil from traveling across the north line of lease F. Therefore, between March 9 and 15 the tubing in the north line well on lease F was raised 20 feet, and at the same time the volume of gas introduced daily into injection well No. 1 was reduced at the rate of 500 cubic feet a day from 70,000 to 43,000 cubic feet. The intention was to create a back pressure on these wells and stop the travel of gas north and across the lease line by building a fluid wall on the north edge of the F lease. Subsequent subnormal decline of oil production on the B and C leases indicated that the travel of oil across the property line from the F lease had been checked, apparently by the application of back pressure on the wells along the north line of the F property. On June 24, oil production on the B lease amounted to 100 barrels and on the C lease to 150 barrels. Although by that time production on the F lease had declined to 183 barrels, this amount was still 13 barrels a day more than was produced prior to gas injection. A short time after raising the fluid level in the wells on the north line of the F lease, production on the J lease increased from 165 to 210 barrels a day, and there was also an increase in production from the wells surrounding the key well on the A lease.

On May 5, 1927, gas was injected into key well No. 2, on the E lease. This well was 1,170 feet deep and penetrated 32 feet of oil formation classified as hard sand. For the first week this well took an average of 19,365 cubic feet of gas a day at a pressure of 145 pounds per square inch. The intake pressure gradually increased and was 375 pounds per square inch on June 9, when the well took only 17,865 cubic feet of gas. On June 15, after a total of 1,175,946 cubic feet of gas had been injected into this well, it ceased to take any further gas and was then shut in. On June 21, the pressure was released, and during the following 14 hours the well produced 63 barrels of oil and 1,500,000 cubic feet of gas test-

ing 0.75 gallon of gasoline per thousand cubic feet. During the following 24 hours 480 barrels of oil flowed from the well. The well was then placed on the gas lift. On July 9 production was down to 10 barrels a day; so the well was again used as an injection well.

At the time that key well No. 2 ceased to take gas, some effect of pressure restoration was noticeable in the surrounding wells, but there was hardly enough to credit gas injection definitely with any increased production. When the pressure on this well was released, however, a noticeable increase was evident in its surrounding wells, which some engineers believe was due, most probably, to surging of the oil and gas in the sand.

After July 10 key well No. 2, functioning again as an injection well, took an average of 57,000 cubic feet of gas daily at pressures varying between 310 and 340 pounds per square inch. Several subsequent attempts at releasing the pressure for an hour failed to make the well again produce oil. Each time the well would make nothing but gas without any drop in pressure, so that it was shut in finally and later was put back on the pump. The injection of gas into key well No. 2 increased total production on the L lease by only about 750 barrels. However, the total increase in production on the E and L leases due to the injection of 4,481,559 cubic feet of gas was 2,550 barrels, an increase of 1 barrel of oil to every 1,758 cubic feet of gas.

Gas injection in key well No. 2 cannot be said to have been entirely satisfactory. Due to the hard sand formation which held the oil in this part of the field, excessively high injection pressures were required, and even then it was difficult to force gas into this formation. Gas injection was tried later in the well adjoining key well No. 2 on the east, but here, too, it proved unsuccessful. Both injection wells were finally put back on the pump.

On the leases shown in Figure 28 and on other leases in the Blake pool the gas seemingly followed the streaks of more porous sand and at the same time remained at the

same structural level. It was also noticeable that the wells on contours below the contour of the key wells were unaffected by the injected gas. The gas seemed to travel toward the well-drilled area of the field, which was also the most highly depleted portion of the sand, only so long as that area was not structurally lower than the key wells. Gas injection in the Blake pool has shown that the course followed by the gas can be controlled to some extent by raising the tubing in the producing wells and thereby placing additional back pressure on the wells. The resulting fluid wall caused the gas to travel along new channels. Attempting to restore pressure in more or less virgin territory was not entirely successful and key wells with high fluid levels would not take gas except at excessively high pressures.

Pressure restoration in the Blake pool on the whole, however, has been successful in recovering many barrels of oil that ordinary producing methods would have failed to recover. The success attained during the test stage in 1927 warranted converting other producing wells into injection wells, and the extent to which this has been carried is indicated by the number of injection wells in this part of the field at present. Figure 28 shows the number of injection wells during the midsummer of 1928, and their relation to property lines, producing wells, and structural features of the producing formation.

POWELL FIELD, NAVARRO COUNTY, TEXAS

During March, 1926, an operator in the Powell Field, Navarro County, Tex., began injecting gas into the producing sand underlying his leases with the object of utilizing waste residue gas to halt encroaching water from the east and to drive oil in a westerly direction toward a fault plane which intersected the pay sand on his properties (see map, fig. 29) and thereby either increasing the oil production or arresting production decline. The numbered leases shown on the map are owned by the operator who carried on the gas injection experiments.

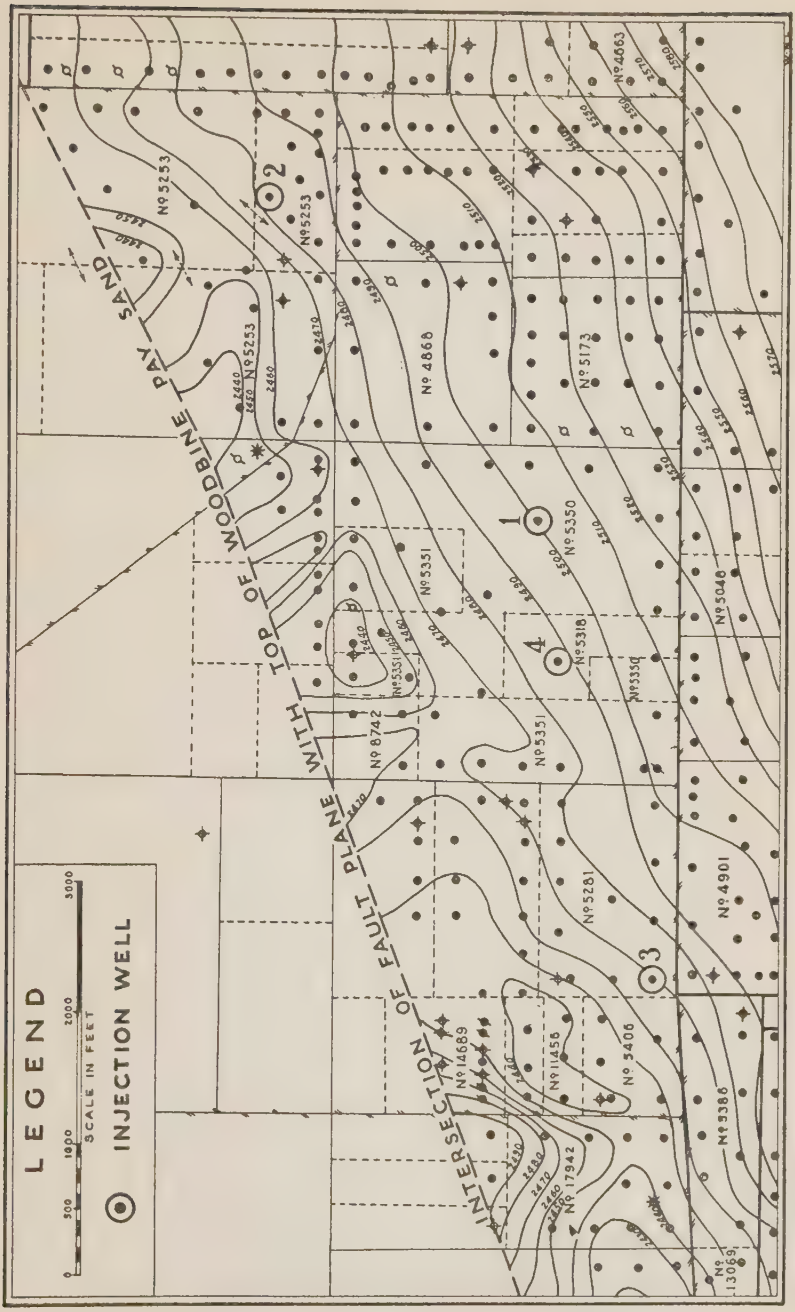

FIGURE 29.—Map of a portion of Powell field, Navarro County, Tex., showing general structure on top of pay sand, and location of injection wells

Injection well No. 1, Figure 29, located on the edge of the water drive where any effect of the gas would manifest itself on this operator's property rather than on that of his neighbors, was selected as the gas-injection or key well. This well was 2,964 feet deep with 41 feet of porous sand at the bottom and had been producing at the rate of 48 barrels of oil and 250 barrels of water daily. When gas was first injected into this well it was necessary to build up the pressure to 485 pounds per square inch. As soon as the gas "broke through" the pressure dropped, and at the end of the first 24 hours was 240 pounds per square inch. A further decline in pressure occurred during the next few days, and from then on until September 8, 1926, when the gas compressor was shut down, the injection pressure remained at 190 pounds per square inch.

No decline in oil production was noticeable during the first 10 days following the compressor shutdown, but during the succeeding five days lease oil production dropped from 1,500 to 950 barrels a day. At first this decline was attributed to improper pumping of the wells on the lease, but when, after thoroughly checking the pumping equipment, production could not be increased above 1,000 barrels a day, the compressor was started again on October 1, 1926. A pressure of 370 pounds per square inch was required at the start, but after five days a pressure of 190 pounds per square inch was again sufficient to force gas into the formation. Lease oil production increased slowly until total daily production amounted to 1,200 barrels. The volume of gas injected was then increased from 250,000 to 350,000 cubic feet daily, with no increase in operating pressure. This increase caused oil production to expand until a total of 1,450 barrels was recovered daily. These operating conditions were maintained until April, 1927, when the volume of gas injected into the sand was reduced to 200,000 cubic feet a day because it was supposed that gas was channeling through the sand. An abnormal decline in oil production resulted, whereupon the volume of gas was increased to

400,000 cubic feet a day under a pressure of 240 pounds per square inch. Production immediately returned to its former level.

It is estimated that up to September 1, 1927, a total of 165,700 barrels of oil has been recovered by gas injection that would not have been recovered by ordinary pumping. This oil was recovered by the injection of 156,462,000 cubic feet of gas. In other words, 1 barrel of oil was recovered for every 949 cubic feet of gas injected. Thirteen per cent of the total gas produced on this lease has been injected back into the sand with a resulting increase of 3.4 per cent in oil production.

Not only was additional oil recovered, but the pressure of the injected gas held back encroaching water. Wells up the structure maintained almost the same amounts of water regardless of the increase in oil production. Offset wells to the east of the key well showed no effect of the injected gas. Apparently the gas traveled up the structure toward the fault, spreading out fanwise until a width of about two locations was reached. This test showed that the gas drove the oil up the structure and that the injection of gas into a line well would not drive oil to a neighbor's wells if the offsetting properties were on the down slope of the structure.

In April, 1927, pressure restoration activities were extended, and two other producing wells on the edge of the water drive were converted into gas-injection wells. Key well No. 2 (fig. 29) is 2,940 feet deep, with 17 feet of oil sand; it produced 24 barrels of oil and 185 barrels of water a day just previous to being taken off production and converted into an injection well. Key well No. 3 is 2,968 feet deep and penetrates 71 feet of producing sand. It produced 50 barrels of oil and 250 barrels of water on the day before being converted into an injection well.

A pressure of 370 pounds per square inch was required to make key well No. 2 take gas. After the gas "broke through," the pressure dropped to 340 pounds per square inch, remained at that figure for two months, and then de-

clined to 210 pounds per square inch. To prevent the gas from channeling through the formation, only 25,000 cubic feet of gas per day was injected at the start. This volume later was increased at the rate of 25,000 cubic feet a day every two weeks until 120,000 cubic feet a day was being injected. A close check was maintained on the oil produced from surrounding wells, but no apparent increase was noted. Gas injection, however, arrested the decline of oil production and flattened the decline curve.

Key well No. 3 required a pressure of 160 pounds per square inch to start the gas into the formation. After the gas "broke through" a pressure of 110 pounds per square inch was sufficient to keep it moving into the formation. No effect of gas injection was noted in any of the surrounding wells for four months, but during the fifth month the production of the lease on which key well No. 3 is located increased 50 per cent. The greatest benefits of gas injection were noticeable on the lease immediately west of key well No. 3, where oil production up to September 1, 1927, increased 10,391 barrels or 1 barrel for every 777 cubic feet of gas injected. Assuming that the gas injected into key well No. 3 acted solely on the lease to the west, it is calculated that 5.4 per cent of that lease's gas production has been returned to the sand.

Key well No. 4 was added later to the trio of injection wells, but no data, other than that 480,809 cubic feet of gas was injected during the first 14 days, are available.

COOK POOL, TEXAS

Repressuring with gas in the flush stages of production has been practiced in the Cook pool, Shackelford County, Tex., for one and a half years. This project is unique in that it has been instrumental in developing a practice of controlling drainage on competitive properties.

The producing sand in the Cook pool is found at depths of 1,100 to 1,350 feet and varies in thickness from 6 to 30 feet, averaging about 20 feet. The productive area on

July 1, 1928, was approximately 1,400 acres. The first production from the pool was in March, 1926. Drilling was carried on at a leisurely rate, and by March, 1927, there were approximately 200 producing wells. In August, 1928, there were 203 wells producing from the Cook sand, 7 from an upper sand, and 1 from a deep sand. The well spacing is 300 feet. The initial reservoir pressure is not known definitely, although it is generally believed to have been about 250 pounds per square inch. Only about 10 per cent of the wells flowed naturally when brought in, and then only for a period of 60 to 90 days. The gravity of the oil varies from 37 to 41° A. P. I.

For a period of three weeks, during April and May, 1927, experimental work was carried on to determine the practicability and advisability of repressuring the pool while it was still in the flush stage of production. The preliminary work is described by Foran [19] as follows:

"A representative area in the south part of the pool was chosen for a repressure test, and operations were started April 9, 1927. The area in which the tests were carried on showed a rock pressure of from 90 to 110 pounds per square inch, these pressures being determined by pressure gages submerged to the bottom of the full static column of oil. Although an abundance of gas was available at the start of operations, air was injected in the sand for 10 days through a well which had been a regular producer but was temporarily killed in order to serve as an input well.[20] The input well was surrounded by eight producing wells, four being direct offsets and four, diagonal offsets.

"A two-stage portable compressor served to inject the air into the sand. The input pressure required was 165 pounds. The meters showed that a total of 770,000 cubic feet of air had entered the sand during the first 10 days. The air was then discontinued, and residue gas was returned to the sand during the remainder of the test period.

[19] Foran, E. V., Effect of Repressuring Producing Sands during the Flush Stage of Production: Petroleum Development and Technology in 1927, A. I. M. E. 1928, p. 294.

[20] Air was used to determine the extent and movement through the sand.

"Increases in production of the surrounding wells were observed on the sixth day following the start of operations. The casing-head gas from the surrounding wells was analyzed for air during the next 40 days. The air appeared in six of the wells in a highly diffused state, which was indicated by the fact that the air content of the gas did not exceed 4 per cent at any time during the 21 days that it was present as a component of the output gas. The air made its first appearance 14 days following the start of operations and disappeared 35 days after the start. There was no evidence of channeling, and the ratio did not change from that of the normal pre-testing period."

The data given in the following tabulation show that the restoration of pressure during the test period was effective in increasing the amount of oil produced from the eight offset wells without changing the ratio of gas to oil, indicating that the injected air and gas were instrumental in driving oil to the producing wells. The data show further that 13 days after the test was terminated oil and gas production had declined to a figure considerably below that prior to the repressuring test.

Week ended	Oil production, daily average, bbls. per day	Gas production, daily average, cu. ft. per day	Gas-oil ratio, cu. ft. per bbl.	Remarks
April 15.......	534	208,000	389	Normal operations
April 22.......	564	233,000	413	Air and gas injected 88,000 cu. ft. daily
April 29.......	571	245,000	428	Gas injected 91,000 cu. ft. daily
May 5.......	575	241,000	419	Gas injection terminated
Test—May 18.	420	184,000	438	Decline following restoration

On July 13, 1927, a 4,500,000 cubic foot daily capacity gas compressor plant was completed and started to return gas to the sand through 14 injection wells, each taking a different volume of gas at a different pressure. The volumes of

gas injected and the input pressures on September 8, 1927, were as follows:

Section No.	Lease	Well No.	Intake pressure, lbs. per sq. in.	Volume of gas injected, cu. ft. per day	Remarks
84	D	11	67	20,000	
84	D	16	65	23,000	
60	D	16	193	50,000	
61	C	3	105	65,000	
85	B	14	206	53,000	
60	B	14	175	66,000	
84	F	7	101	62,000	
84	A	15	61	23,000	Water area
84	B	17	67	59,000	" "
84	B	18	72	63,000	" "
85	A	13	130	63,000	
60	G	8	88	64,000	
60	G	3	60	175,000	Dry gas area
59	C	9	60	175,000	" " "

A comparison of the location of the input wells as designated in the above tabulation by section, lease, and well number, and those shown on the map (fig. 30) will reveal the fact that some changes have been made in the location of injection wells since September, 1927. Also, one additional input well was added to repressure the isolated producing area in the southern part of section 85. Such changes have made it possible to balance reservoir pressures more effectively.

From the beginning of the repressuring project until February, 1928, production in the pool was on a proration basis. During that period an average of approximately 1,100,000 cubic feet of gas was injected into the sand daily. Since the termination of the proration agreement the daily average volume of gas injected has averaged 2,500,000 cubic feet. On August 1, 1928, the total volume of gas returned to the sand was 678,000,000 cubic feet. As production from the pool was held back during the first seven months after repressuring started and because the aim of the operators in

the field has always been to conserve the oil underground for future recovery, no estimate of the probable increase in ultimate oil production can be made at this time.

FIGURE 30.—Structural map of a portion of the Cook pool, Shackelford County, Tex., showing location of injection wells

The principle of controlling drainage on competitive properties by balancing input gas-well pressures so as to maintain the same reservoir pressure is described by Smith[21] as follows:

" That principle is the balancing of reservoir pressures on one lease against the other. Primarily it is important when offset leases are owned by different companies.

[21] Smith, Lawrence E., Controlling Drainage on Competitive Properties in Early Field: National Petroleum News, October 3, 1928, p. 26.

" Control is obtained chiefly by regulation of the volume of gas returned to the sand. It was assumed early in the work that, if the true reservoir pressures of the input wells could be ascertained, the movements of gas and oil could be controlled, not accurately of course, but workably close. Drainage of one lease by wells on an offset lease is governed by differential in reservoir pressure. If no differential exists, or if it is negligible, drainage will not occur. That is fundamental in oil-field development and is the reason why operators complete offsets to a discovery well as quickly as possible.

"Assume that two adjoining leases have the same reservoir pressure. One operator desires to produce at a lesser rate than the other. Ordinarily, it is argued that it cannot be done; one must produce at the same rate as the other. In the Cook pool it has been demonstrated that such is not the case. Balancing of pressures on offset leases is possible within a few pounds, so that one operator may prorate production while the other takes all his wells will produce, if desired.

" Such balancing is largely obtained by increasing or decreasing the volume of gas returned to the sand. An operator might begin prorating while the neighbor continued to produce at the full rate. The latter, of course, would thereby reduce the reservoir pressure at greater rate than would the offset who was partly shut in, and unless this condition were corrected by restoring the pressure equilibrium by adding a greater volume of gas, the one who was prorating would lose oil. Gas-oil ratios would not be a true index to what was occurring, but reservoir pressures would.

" Closed-in tests to determine reservoir pressures are taken on each of the input wells every 15 days. Gas-oil ratio records also are kept regularly, as without them there would be no guide to the efficiency of operation. The control of reservoir pressures, however, is the new technic that has been worked out in the Cook field, and the interested companies are now beginning on their attempt to balance pressures all over the field, regardless of whether there are offset owners to consider. A more even reservoir pressure over the field will mean uniformity in producing conditions, more even rates of gas to oil and an all around more efficiently handled property.

" With the control of sand pressures by changes in volume of input gas, attention is paid to control of gas-oil

ratios which supplements the former. This form of control is by maintenance of back pressures on the producing wells. After trying other methods, the operators standardized on adjustment of rod stroke so that the producing formation would never be uncovered but there would always be fluid at a sufficient elevation above the top of the sand to maintain the desired back pressure. It requires about 15 days to determine the efficiency point in back pressures.

"Multiplier posts are installed at all wells to provide the change of length of stroke; frequencies of stroke are not disturbed. By changing the length of stroke a critical point finally is found beyond which the well will cease its decline in feet of gas per barrel of oil and will start increasing in gas. Real stability and control of the movements of gas through the sand are obtained by this method of holding fluid level high enough to maintain proper back pressure against the sand.

"In selecting input wells, geographical location and productivity of the wells were considered. Poor wells were selected. It was believed that their small production indicated sand tighter than in wells of larger production and the intent is to move the oil from the tight sand to the looser zones, where the fluid travel is greater. It has been proved that the wells that were the best producers before repressuring respond best under the gas drive. Further, the areas showing least free gas are the areas of highest concentration of oil and hence are the most responsive to the pressuring.

"Summarizing, the work in the Cook pool has demonstrated that pressures in a field and on competitive properties can be controlled in the sand to the point where the question of drainage becomes unimportant. It has shown that a uniform rate of production can be maintained for an extended period and that the ultimate recovery can be greatly increased. It has proved that the most economic use to which gas from a gasoline plant can be put is its return to the sand. It has demonstrated that water encroachment can be stopped."

EXAMPLES FROM EASTERN FIELDS

The reports presented at the Ponca City meeting by the regional subcommittees of the American Petroleum Institute's committee on gas conservation, which are the

nucleus of this coöperative paper, did not include a report from the eastern subcommittee. Since that meeting, however, a paper has been prepared by Haskell,[22] and the substance of the following paragraphs has been taken from his report.

BRADFORD FIELD

The application of pressure has been productive of good results in those areas in the Bradford field, Pa., where the sand is unconsolidated and where the initial productions of the wells ranged from 50 to 200 barrels per day. In some of the fields where the sands are compact the results have not been quite so good. In one area of 266 acres in which the sands are unconsolidated, 41 wells (one well to 6.48 acres) were drilled between 1885 and 1896. Air, because gas was not available, was first injected into the sand in this area through nine key wells in October, 1925. The daily input of air per well averaged 68,600 cubic feet at 300 pounds' pressure. The results of repressuring were quickly apparent. Many wells with an average normal production of 0.25 barrel of oil per day prior to air injection increased their production to as much as 12 barrels a day in less than two months. All of the wells were more or less affected by increased pressure due to the injection of air, but the production from only 22 wells increased appreciably. The production from the wells was 3,474 barrels in 1925, 15,697 barrels in 1926, and 18,524 barrels in 1927. The 1928 production is expected to be only slightly lower than that of 1927. Water flooding played no part in the increased oil recovery. Neither can new completions be credited with appreciably increasing oil production, because only one new well was drilled in subsequent to the application of pressure restoration methods.

In certain areas of the Bradford field where the sands are consolidated, only 15,000 cubic feet of air per day at 475

[22] Haskell, R. M., Pressure Restoration in the Eastern Fields: American Petroleum Institute, Development and Production Engineering Bulletin 202, p. 149, 1928.

pounds pressure can be injected into key wells. In one of these "tight" areas, water flooding was carried on in a small way for five years without increasing oil production materially, but since the initiation of gas injection production has increased 25 per cent.

ROBINSON SAND IN ILLINOIS

Beginning in November, 1926, air was injected into an area in Crawford County, Ill., where oil production was obtained from 135 wells. These wells were drilled between 1907 and 1912, and the area was gas-pumped for 10 years prior to repressuring. Air was injected through 18 key wells, each taking an average of 32,325 cubic feet per day at 230 pounds pressure. In spite of the fact that production in this district has not been pushed, the average daily oil production from the 135 wells has increased from 0.40 barrel per day to 0.98 barrel per day. Moreover, this increase of nearly 150 per cent in oil production was obtained by pumping the wells only three times a week, as against six times a week before gas injection was started. Oil production was 80 per cent higher in 1927 than in 1926, and the first four months of 1928 showed an increase of 60 per cent over that for the corresponding months in 1927.

GAS DRIVE IN ROCKY MOUNTAIN FIELDS

SALT CREEK FIELD

The gas drive was first used in the Salt Creek field in 1926, at which time considerable gas in excess of fuel and market requirements was being discharged to the air from the gas plant. Four wells in the Second Wall Creek sand were taken off production and used as key or injection wells to determine the value of the gas drive. The results of this preliminary test were so encouraging that the gas drive process was extended to 25 key wells. During August, 1927, a daily average of 20,500,000 cubic feet of gas—820,000 cubic feet per key well—was introduced into the Second Wall

Creek sand at a pressure of 140 pounds per square inch. The following effects of the gas drive on oil production were noted:

1. Offsets to the original four key wells showed a combined increase in production from 435 barrels per day to 525 barrels per day in a period of four months, which was a gain in daily production of 20 per cent. After the peak of 525 barrels had been reached, the production declined along a new curve considerably above the extension of the old production curve.

2. Offsets around nine of the key wells showed an average increase of 15.75 per cent over a period of four months, and on September 1, 1927, the production was still increasing.

3. Offsets around eight of the key wells showed first an arrested decline, followed by a trend slightly upward in the third and fourth months after introduction of gas was begun.

4. Offsets to three key wells showed an increased decline as a result of the gas drive due to gas channeling through the sand. It was therefore necessary to discontinue introduction of gas in these localities.

One of the key wells was used to introduce into the sand a gas made up of approximately 65 per cent propane and butane and 35 per cent methane, ethane, and other gases. Most of this gas was in liquid state at atmospheric pressure and prevailing atmospheric temperature, and the greater part was put into the well in liquid form at 100 pounds (gage) pressure. No measurements were made of the amount of heavy gas and liquid injected, as their proportions were continually changing with the rise and fall of temperature. As much as 60,000 gallons of liquid, however, are known to have been returned to the oil sand in one day.

Subsequent to the injection of this heavy gas, marked increases in production were noted in five wells surrounding the key well. The combined production of these five wells increased from 140 to 245 barrels a day in three months. The available volume of heavy gas was then distributed to

a large number of key wells. This method of gas distribution decreased materially the amount injected daily into the original key well, and after 30 days production from its five surrounding wells decreased rather rapidly. The key well was then connected to the regular gas-drive system to take fuel gas at a pressure of 140 pounds per square inch.

Several general conclusions have been drawn from the gas drive test in the Salt Creek field:

1. Oil production in the majority of wells increased as a result of the gas drive in the wells surrounding the key wells. In some the increase was immediate but in others it was not noticeable for several months. In a few wells the gas channeled through the sand and decreased the oil production so that it was necessary to discontinue these key wells. From one key well in particular gas channeled to an adjoining well 660 feet away and in three days killed the oil production. The gravity of the oil and its gasoline content were unaffected by the gas drive.

2. Gas production in the majority of cases increased as a result of the gas drive, with an attendant increase in gas-oil ratio. In some wells gas-oil ratios were reduced as the oil production increased, the gas production remaining approximately the same. Where gas production increased there was usually an attendant drop in gasoline content per thousand cubic feet, but the total gasoline content remained approximately the same.

ELK BASIN FIELD

In order to test the possibilities of the gas drive in the Elk Basin field, Wyo., gas from the gas zone which underlies the Second sand was injected at a pressure of 50 pounds per square inch into two key wells. After three months a marked increase in oil production was noted in the wells surrounding these two key wells. As a result of the success of this experiment, three operators joined in rehabilitating a gas plant to compress casing-head gas for injection into

12 key wells. The gas plant was started during June, 1927, and delivered approximately 100,000 cubic feet of gas a day at a pressure of 40 pounds per square inch to each key well. Table 9 shows the percentage increase in oil production as a result of the gas drive.

TABLE 9.—PRODUCTION DATA BEFORE AND THREE MONTHS AFTER BEGINNING THE GAS DRIVE IN THE ELK BASIN FIELD, WYO.

Lease	No. of producing wells	Daily average oil production, bbls.		Increase, per cent
		Before gas drive, May 1927	After gas drive, Aug. 1927	
1	19	180	212	18
2	21	53	70	43
3*	52	417	497	19

* Combined production of one company.

DATA ON THE SEAL BEACH FIELD, CALIF.

In the Seal Beach field, Calif., gas injection was started while several wells were still flowing naturally. Extra high injection pressures are required because of the hydrostatic pressure exerted by high-head edge water. In these two respects, the Seal Beach experiments differ from other gas drive tests.

During the latter part of 1927 gas was injected through three intake or key wells into the Bixby sand which lies approximately 4,400 feet below the surface. Pressures as high as 1,800 pounds per square inch were required at the start to force the gas into the sand. After the gas once started into the formation, the pressure never exceeded 1,500 pounds per square inch, and by June, 1928, the working pressure had dropped to 1,350 pounds per square inch. Up to June 1, 1928, the total gas injected into the Bixby sand amounted to 173,000,000 cubic feet.

Production increases as high as 50 per cent were obtained in wells up-structure from the injection wells with little increase in wells down the structure. Gas injection steadied

the flow of two or three surrounding wells which were beginning to surge, and decreased materially the amount of water produced on one edge well. The additional oil recovered due to gas injection up to June 1, 1928, is estimated at 235,000 barrels, or 1 barrel of additional oil recovered for every 736 cubic feet of gas injected. These figures do not take into account additional oil recovered on adjoining leases, which, however, did not run into large figures.

The experience in the Seal Beach field has been that a rapid increase in oil production occurs during the first few months of gas injection and is followed by a decline in production continuing at a fixed figure above that which the decline of the well would have shown had there been no gas drive to stimulate the flow of oil to the producing wells. The effect of repressuring was noticeable several locations away from the key wells (a location is approximately 660 feet in this area), thus necessitating coöperation between lease holders for its use on small properties. It was found also that the tendency of the gas was usually to travel up-structure, and that the most effective key wells were edge wells on the down-structure side of producing wells. Considerable trouble was experienced at Seal Beach because of the channeling of gas to nearby wells. In one well, channeling nullified to some extent the benefits derived from the gas drives. Channeling once started increased at a rapid rate.

Due to the lack of compressor capacity, gas injection was stopped from March until July 1, 1928, and it was found when work was again started that the results were not as good as they had been previous to discontinuing repressuring. According to Bell,[23] it is very probable that this is due to the fact that the high-head edge water encroached in the sand when the flow of gas was stopped, and when gas injection was started again it was of course necessary to drive all of this water ahead to the wells before good results could again be expected.

[23] Bell, A. H., Chief Production Engineer, Marland Oil Company of California.

Experience in the Seal Beach field has shown that the quickest increases in production can be obtained by injecting gas into edge wells on the flanks and driving the oil up-structure. Certain engineers in that field, however, are of the opinion that the greatest ultimate recovery would result from injecting the gas on the top of the structure and driving the oil at a much slower rate and in a more even manner toward the flank wells. They believe that considerably less gas slippage will result in driving oil down-structure than in driving it to structurally higher producing wells.

Exceedingly high pressures were used at Seal Beach. Some operators believe that the cost of compressing gas to a pressure of 1,500 pounds per square inch is excessive. If considered on the basis of compression ratios, the work of compressing gas from 600 to 1,500 pounds per square inch is actually less than is required to compress it from 30 to 600 pounds per square inch. The greatest drawback to these extremely high pressures is in the operation of mechanical equipment without excessive shutdowns and cost.

Gas injection early in the life of a field when formation pressures are still high offers promise of profitable results. Experience in the Seal Beach and other fields in California indicates that if gas-injection equipment is installed early in the life of the field, it is not necessary to install as much gas-lift equipment. In the Dominguez field, for example, 18 wells were taken off the gas lift and flowed naturally subsequent to gas injection.

ABSORPTION OF GASOLINE FROM UNRECOVERABLE OIL

Dry gas is injected into depleted oil sands in the Coalinga and Buena Vista Hills oil fields in California to recover gasoline from unrecoverable oil which adheres to the sand grains. As operations in both fields are practically identical, only the Coalinga project will be described. At

Coalinga, dry gas is injected into the oil sand on one property through a single well at an average pressure of 40 pounds per square inch, and returns to the surface through surrounding pumping wells. Approximately 1 gallon of gasoline per thousand cubic feet of gas circulated through the oil formation is recovered when the "wet" gas is treated in a near-by gasoline plant.

The fluid levels in the wells on this property stand far below the top of the productive sand stratum so that there is opportunity for the injected gas to travel through the upper depleted part of the sand zone. Oil production comes from the lower and less depleted part of the zone and is unaffected by the gas that by-passes through the more depleted sand above the oil level. Oil production, therefore, has not been increased by the circulation of dry gas. However, if enough gas were available to fill the voids in the sand completely and if pressure were built up over the whole structure, it is probable that oil production would be increased.

Circulating dry gas through depleted oil sands is usually profitable. Seldom will the cost of compressing and injecting gas into such formations exceed a few cents per thousand cubic feet. On the other hand, the value of the gasoline recovered is several times the cost of manufacturing it, so that the resulting profit makes such operations lucrative; at the same time, the oil operator increases his supply of gasoline without affecting his reserves, because gasoline absorbed from unrecoverable oil otherwise would be lost.

GAS STORAGE IN CALIFORNIA

Although the primary purpose of injecting gas into partly depleted oil sands has been to increase the recovery of oil, certain operators in California are now storing surplus gas in favorable reservoirs to be re-produced when gas consumption exceeds the demand. The necessity of providing large storage for surplus gas is nowhere more pronounced than in southern California where the supply of natural gas

varies over a wide range and the fluctuations are entirely unrelated to the market for gas.

Nearly all natural gas produced in California is a by-product of oil-producing operations, and the supply is therefore dependent mainly on the rate of production of oil. Variations in supply are thus due primarily to the discovery of new fields or to finding new sands in old fields. Less important fluctuations in supply result from the increase or decline of existing sources; the curtailment and shutting in of oil production; and the changes in gas-fuel requirements of oil operators for drilling, producing, transporting oil through pipe lines, and refining.

Depleted and nearly depleted oil sands are natural reservoirs of large capacity, and it is believed that almost if not all of the gas stored in them can be recovered eventually. Moreover, natural gas stored in depleted oil sands absorbs gasoline from the unrecoverable oil adhering to the sand grains. This gasoline will be obtained upon recovery of the stored gas and thus increase the supply of gasoline to the oil operator. Although the absorption of gasoline by natural gas in storage is usually considered of secondary importance, actually it may prove to be more important than is generally assumed.

Thus the storage of surplus gas in depleted oil sands benefits the oil operator by increasing his supply of gasoline, gives the gas companies a reserve upon which to draw during the winter months or at other times when the demand exceeds the supply, and curtails waste of gas which otherwise would occur during periods of flush production.

VARIATIONS IN SUPPLY OF GAS

The discovery of a new field in southern California, or the finding of a deeper sand in an old field, invariably makes available large quantities of gas for which there is no immediate market. Moreover, when three fields, such as the

Huntington Beach, Santa Fe Springs, and Long Beach, reach their peak production at about the same time, the waste of gas is enormous. It may be noted in Figures 1, 2, and 3 that this condition existed in California in the fall of 1923. The total gas production from these fields in October, 1923, was approximately 1,045,000,000 cubic feet a day. Ten months before, the total production from these three fields had been only 375,000,000 cubic feet a day.

Since these three fields reached their initial peak, new fields have been discovered one by one, or old wells have been drilled deeper, and each in turn has produced large volumes of gas during its flush production period. Only a few outstanding examples need be cited to show the enormous production of gas that accompanies the discovery of new sources. In April, 1927, the Ventura field produced approximately 210,000,000 cubic feet of gas a day; and during the summer of 1927 Alamitos Heights reached a peak gas production of 102,000,000 cubic feet a day; on December 1, 1928, as a result of the summer's deeper drilling in the Long Beach field, surplus gas production amounted to 125,000,000 cubic feet a day. It is estimated that in January, 1929, the Santa Fe Springs field will have a daily gas production of 387,000,000 cubic feet from the recently discovered Buckbee oil zone. Of this amount, 274,000,000 cubic feet a day will be surplus above the amount required for field and plant fuel, taken out by public utility corporations, and that used in repressuring the Meyer sand which lies above the Buckbee zone.

The supply of gas is by no means stable. Gas production in the Long Beach field in 1923 (fig. 2) dropped from 395,000,000 to 145,000,000 cubic feet a day in 12 months. During the same year and in the same length of time gas production in the Santa Fe Springs field dropped from 510,000,000 to 45,000,000 cubic feet a day. Gas production in Alamitos Heights declined from 102,000,000 cubic feet to 29,000,000 cubic feet a day in three months, and it is estimated that the

gas production from the newly discovered Buckbee zone in the Santa Fe Springs field will have dropped in 12 months from a peak of nearly 400,000,000 cubic feet to 52,000,000 cubic feet a day.

VARIATIONS IN DEMAND FOR GAS

Not only does the supply of gas fluctuate but there is a large variation in the demand for gas for different industrial and domestic uses in southern California. Industrial demand usually is fairly constant, but at times and for various reasons even this demand fluctuates widely and sometimes unexpectedly. The principal domestic demand is for cooking, water heating, and space heating. This demand varies over a wide range, hourly, daily, and seasonally. The magnitude of this variation in domestic demand is indicated by the following typical ratios given by Bridge:[24]

	Hour during 24-hour period	Day during one week	Day during one month	Day during one year	Month during one year
Ratio of Maximum/Minimum.	28	1.9	2.9	5.6	3.1
Ratio of Maximum/Average...	2	1.5	1.7	3.0	1.8

According to the same authority,

" the domestic demand of one gas company's system on January 12, 1928, was 52,290,000 cubic feet, and 99,389,000 cubic feet on January 18. During December, 1927, the domestic demand for all of southern California varied from 98,785,000 cubic feet to 197,884,000 cubic feet. These violent fluctuations, amounting in total to about 100,000,000 cubic feet daily within a single month, are due to the general use of gas for house heating and extreme changes in temperature.

[24] Bridge, A. F., Variables of Natural-Gas Production and Utilization in California: A report to the California Operators Committee on Gas Conservation, 1928.

" Figure 31 shows the monthly variation of domestic, industrial, and total demand for gas for southern California during 1927.

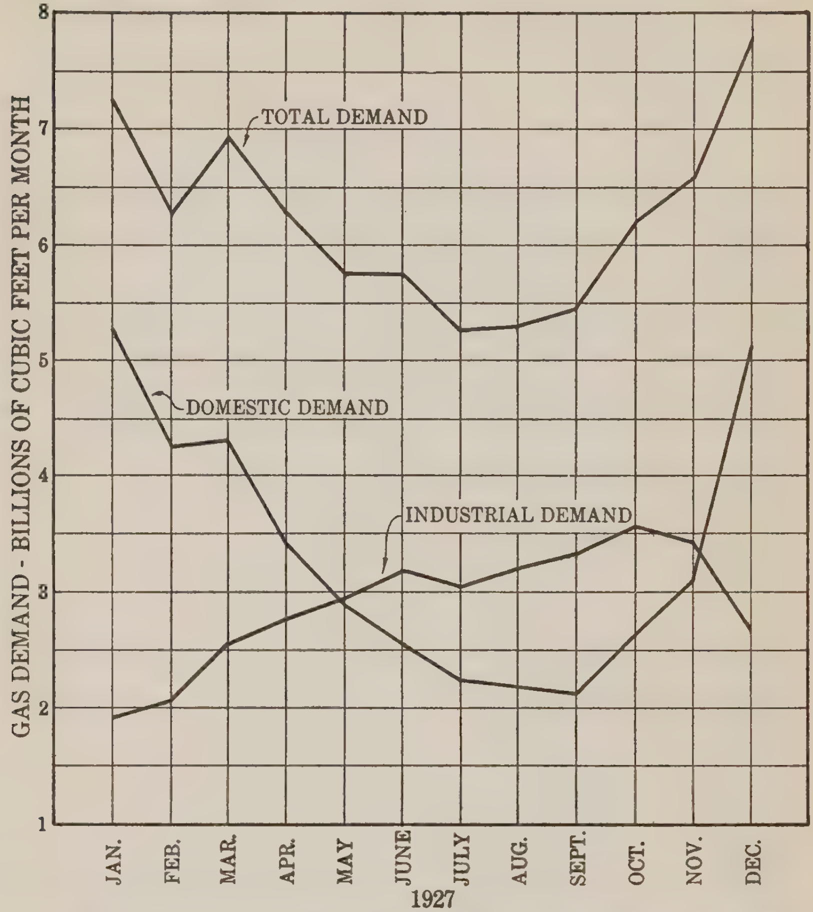

FIGURE 31.—Monthly variation of domestic, industrial, and total demand for gas for Southern California (Los Angeles and vicinity). (After A. F. Bridge)

METHODS USED BY GAS COMPANIES TO MEET VARIATIONS IN DEMAND

" Gas companies arrange to purchase gas in the various fields, at least sufficient to meet their domestic and commercial requirements, with a reasonable margin of safety. Compressors, transmission lines, and distributing facilities must be provided to handle this quantity of gas from field to con-

sumer. The reserve supply of dry gas is drawn upon during periods of heavy load, but this represents only 4 per cent of the total send-out. Storage holders are employed to absorb the hourly fluctuations in load, and thus supplement delivery from field stations during peak hours.

"Deliveries of gas to industrial consumers are curtailed during periods of heavy domestic demand, and by this means daily fluctuations up to about 65,000,000 cubic feet can be absorbed. On days of maximum domestic demand, such as often occur during December, there is still a considerable volume of industrial consumption. This is due partly to the fact that some industries cannot substitute other fuels for gas on short notice, and in part represents the margin of safety of supply over domestic demand, which would have been wiped out by colder weather. There is a difference between domestic maximum winter and minimum summer daily demands in southern California amounting to more than 140,000,000 cubic feet. Since the industrial market absorbs only 65,000,000 of this amount, the remainder is blown to the air during periods of minimum demand. It should be noted that this is the blow-off resulting from variations in demand only, or in other words, the waste which would occur if the supply were just adequate to meet peak daily requirements. When, as in Long Beach in 1928, the flush production occurs in the summer months, blow-off is correspondingly increased.

"The layman frequently inquires why gas holders cannot be constructed to store the excess supply accumulating over a period of months or years, as is done with oil and its refined products. This is an economic impossibility because the commodity is a gas and not a liquid. It is not feasible to provide gas storage above ground of greater capacity than the cumulative difference between supply and demand which occurs in one or two days. This will be evident from the following relations between cost of storage and commodity, for gas and oil."

Commodity	Volume unit	Nominal value in field	Cost of * storage per volume unit	Ratio of storage cost to value of commodity
Natural Gas	M cu. ft.	$0.10	$75.00	750
Crude Oil	barrel	1.00	0.35	0.29

* Holders and tanks of large size.

Underground storage offers a partial solution of the gas conservation problem in California. Natural reservoirs of large capacity are available in certain partly drained oil fields and it is possible to store considerable gas by utilizing these fields. Storage is accomplished by compressing the gas to pressures sufficient to inject it into the oil sands against the hydrostatic pressure, through wells which are taken off production for this purpose. Bridge[25] lists the factors which determine the suitability of a field for gas storage in the order of their importance, as follows:

1. Limited number of operators controlling a closed structure, so that joint storage and withdrawal is possible.
2. Presence of sands which will permit injection at a practical input rate per well.
3. Gas transportation facilities from source in which surplus originates to the field under consideration.
4. Proximity to market.
5. Injection pressure required.
6. Mechanical conditions of wells.

STORING GAS IN DOMINGUEZ FIELD

The Dominguez oil field, shown in Figure 32, is one of the most suitable large fields in California for storing gas underground. This field comprises approximately 1,950 acres of proved oil land and is controlled by only three oil companies. The oil and gas producing measure, the Callendar zone, is about 3,700 feet below the surface at the top of the structure, and by coöperative agreement between operators, all wells, with the exception of several deep tests, were drilled only 400 feet into the producing sand. These favorable features—size, control, and depth of development—augmented by the close proximity of the field to sources of surplus gas and the wide and uniform spacing of the wells make Dominguez an ideal field for the successful operation of a gas storage project. Wells are spaced about 600 feet apart; this spacing is an advantage in gas storage opera-

[25] *Op. cit.*

tions because the great amount of formation between the wells offers resistance to migration of injected gas and tends to prevent it from channeling to producing wells. This advantage is of paramount importance in the Dominguez storage project, because the producing oil wells are not shut in but are allowed to produce under back pressures.

Previous to the inauguration of the gas-storage project in May, 1928, repressuring operations had been under way

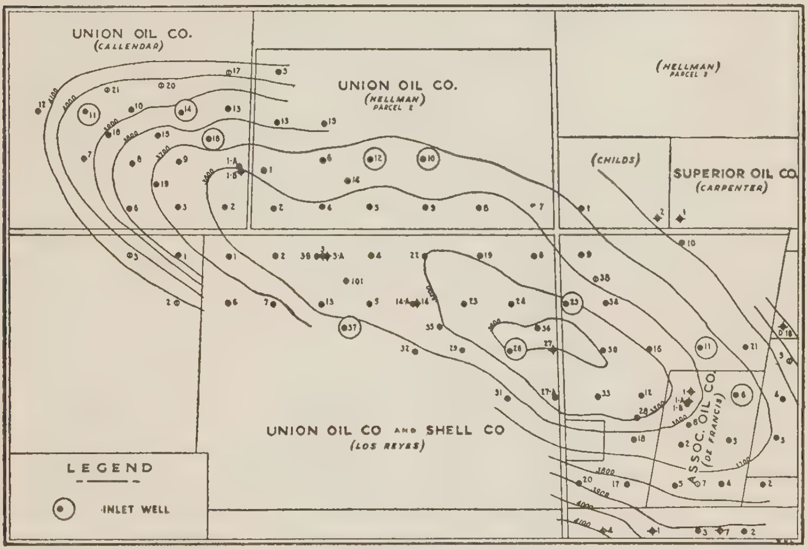

FIGURE 32.—Subsurface contour map, Dominguez field, Calif. (After E. W. Masters)

since September, 1926, when the Union Oil Co. and the Shell Oil Co. each began injecting 1,500,000 cubic feet of gas daily into the reservoir sands. The volume of gas circulated by the Union Oil Co. was increased during February, 1928, and by May, 1928, about 4,000,000 cubic feet daily was being injected by this company through the injection wells Hellman 12 and Callendar 14. Injection pressures during the repressuring project were 440 pounds per square inch on the Shell Oil Co.'s property and 640 pounds per square inch on the Union Oil Co.'s properties. Thus it was known prior

to inception of the gas-storage project that injection pressures were within the practical working limits of compressor equipment.

At the beginning of the storage project the Union Oil Co. and the Shell Oil Co. each agreed to inject 10,000,000 cubic feet of gas daily and to hold necessary back pressure on their producing wells to keep the injected gas in the oil sand. The gas injected was from the Long Beach and other nearby fields and represented surplus gas that otherwise would have been wasted. Gas-storage operations began during the first week in May, 1928. Table 10, taken from a report by Masters,[26] lists the wells that were taken off production and used as gas inlet wells, and the volumes and pressures of the injected gas as of July 1, 1928. It may be noted that relatively high pressures were required to inject large volumes of gas into the wells that were located on the edge of the structure.

TABLE 10.—GAS INJECTION VOLUMES AND PRESSURES AS OF JULY 1, 1928, DOMINGUEZ FIELD, CALIF.

Inlet well	Volume of gas injected daily, M cu. ft.	Pressure, lbs. per sq. in.	Remarks
Callendar 11.........	....	...	
14.........	2,500	750	Edge well
16.........	240	460	
Hellman 10.........	250	480	Edge well
12.........	2,200	548	Edge well
14.........	2,000	500	
Reyes 7.........	1,000	720	Edge well
25.........	2,700	580	Crest well
26.........	3,200	490	Crest well
33.........	400	740	Crest well (cuts 36 per cent)
37.........	1,300	660	Edge well

[26] Masters, E. W., Gas Storage, Dominguez field: A paper presented before District Meeting of Division of Development and Production Engineering of the American Petroleum Institute at Los Angeles, California, September 21, 1928.

Masters' report gives the following additional information on the gas storage project at Dominguez:

During the month of August, the volume of gas distributed to each inlet well was varied from time to time to give a better distribution throughout the structure and to help prevent channeling and by-passing to nearby producing wells. Reyes 3-B and 4 always produced with high gas-oil ratios, and many experiments aiming to increase their recovery efficiencies resulted in reducing gas-oil ratios only slightly. After starting gas storage operations, gas production from both wells increased gradually. Attempting to flow Reyes 3-B and hold back pressure on Reyes 4 gave unsatisfactory results, and both wells were then shut in completely. In order to carry out the spirit of the operating agreement the Union Oil Co. held back pressures on its offset wells, Hellman 4 and 5, comparable to those developed in Reyes 3-B and 4. Still another change in operating methods was made; by the latter part of August, injection pressure on Reyes 33 had become very high, and because only a small volume of gas entered the well it was put back on production and Reyes 11 used as an injection well in its place.

A total of 1,541,224,000 cubic feet of gas was injected into the Dominguez oil zone during the period May 1 to September 1, 1928, and it is estimated that 1,232,979,000 cubic feet, or 80 per cent of the volume injected, has been held in the structure as stored gas.

Shortly after September 1, 1928, the Associated Oil Co. started to pump surplus gas from the DeFrancis lease into its DeFrancis No. 6 well. Although only 200,000 cubic feet of gas was injected daily at the start, plans were made for increasing this amount at an early date to approximately 1,000,000 cubic feet a day.

The volumes of gas injected daily into each inlet well and the corresponding pressures at which the wells took gas are shown in Table 11.

TABLE 11.—GAS-INJECTION VOLUME AND PRESSURES AS OF SEPTEMBER 1, 1928, DOMINGUEZ FIELD, CALIF.

Inlet well		Volume of gas injected daily, M cu. ft.	Pressure, lbs. per sq. in.
Callendar	11	200	650
	14	3,000	775
	16	150	595
Hellman	10	940	515
	12	3,000	670
	14	300	450
Reyes	11	1,800	440
	25	3,000	620
	26	3,600	560
	37	1,500	540

Gas storage has had a pronounced effect on the majority of producing wells in the field; according to Masters[27]:

"The tendency of gas-lift wells to flow naturally after the gas-storage project was started has been especially noticeable. Thirty-seven wells were being flowed by gas lift before the project was begun, and these wells required a total daily dry gas circulation of 9,220,000 cubic feet. By September the total number of wells on gas lift had been reduced to 19, so that 18 wells were flowing naturally again. This effected a reduction in the amount of dry gas circulated of 4,952,000 cubic feet and a pronounced saving in lifting costs. Moreover, observations indicated that several of the remaining gas-lift wells would soon flow naturally again and thereby still further reduce lifting costs.

"It is becoming increasingly difficult to prevent injected gas from returning to the surface. By the middle of September, 1928, wells Reyes 3-B, 4, 23, and 101 were shut in completely because they dissipated stored gas. In addition, 22 flowing wells had to be beaned back and high back pres-

[27] *Op. cit.*

sure maintained on four pumping wells. Table 12 lists influenced wells and gives an idea of the effect caused by the injection of gas and the measures taken to prevent increasing daily gas production. All flowing and gas-lift wells, with one

TABLE 12.—STATUS OF WELLS INFLUENCED BY THE INJECTION OF GAS IN THE DOMINGUEZ FIELD, CALIF., BEFORE AND FOUR MONTHS AFTER INITIATION OF THE GAS-STORAGE PROJECT

Well		Before	After four months		
			Status (9/1/28)	Tubing pressure, lbs. per sq. in.	Casing pressure, lbs. per sq. in.
Callendar	1...	Gas-Lift-Open-Flow	Flowing-Beaned	145	170
	2...	Flowing-Open-Flow	Flowing-Beaned	145	170
	8...	Gas-Lift-Open-Flow	Gas-Lift-Beaned	10	280
	9...	Gas-Lift-Open-Flow	Flowing-Beaned	10	140
	10...	Gas-Lift-Open-Flow	Gas-Lift	15	160
	15...	Gas-Lift Beaned	Flowing-Beaned	110	240
	18...	Gas-Lift	Gas-Lift	15	260
Hellman	1...	Gas-Lift-Open-Flow	Flowing-Beaned	90	180
	2...	Gas-Lift-Open-Flow	Flowing-Beaned	30	150
	4...	Gas-Lift-Open-Flow	Flowing-Beaned	160	260
	5...	Gas-Lift-Open-Flow	Flowing-Beaned	155	230
	6...	Gas-Lift-Open-Flow	Flowing-Beaned	130	260
	9...	Gas-Lift-Open-Flow	Flowing-Beaned	0	140
	11...	Gas-Lift-Open-Flow	Gas-Lift	10	120
	13...	Gas-Lift-Open-Flow	Flowing-Beaned	26	170
Reyes	2...	Flowing-Open-Flow	Flowing	10	150
	3B..	Pumping	Shut-in	...	260
	4...	Pumping	Shut-in	...	260
	5...	Flowing-Open-Flow	Flowing-Beaned	100	270
	8...	Gas-Lift-Open-Flow	Flowing-Beaned	150	320
	9...	Gas-Lift-Open-Flow	Pumping	0	80
	12...	Gas-Lift-Open-Flow	Gas-lift	10	170
	13...	Pumping	Pumping—No back pressure	...	...
	14...	Gas-Lift-Open-Flow	Flowing-Beaned	40	160
	16...	Gas-Lift-Open-Flow	Gas-Lift-Beaned	8	180
	19...	Gas-Lift-Open-Flow	Flowing-Beaned	80	200
	22...	Gas-Lift-Open-Flow	Flowing	60	180
	24...	Flowing-Open-Flow	Flowing-Beaned	90	350
	30...	Gas-Lift-Open-Flow	Flowing-Beaned	30	200
	31...	Pumping-Gas-Lift-Open-Flow	Flowing-Beaned	20	200
				...	...
	33...	Pumping	Pumping	...	25
	34...	Gas-Lift-Open-Flow	Flowing-Beaned	80	240

exception, were producing through open tubing prior to the initiation of the gas storage project. However, by the middle of September, 1928, these wells were producing against high back pressures which in a number of wells exceeded the operating pressures two or three years previous.

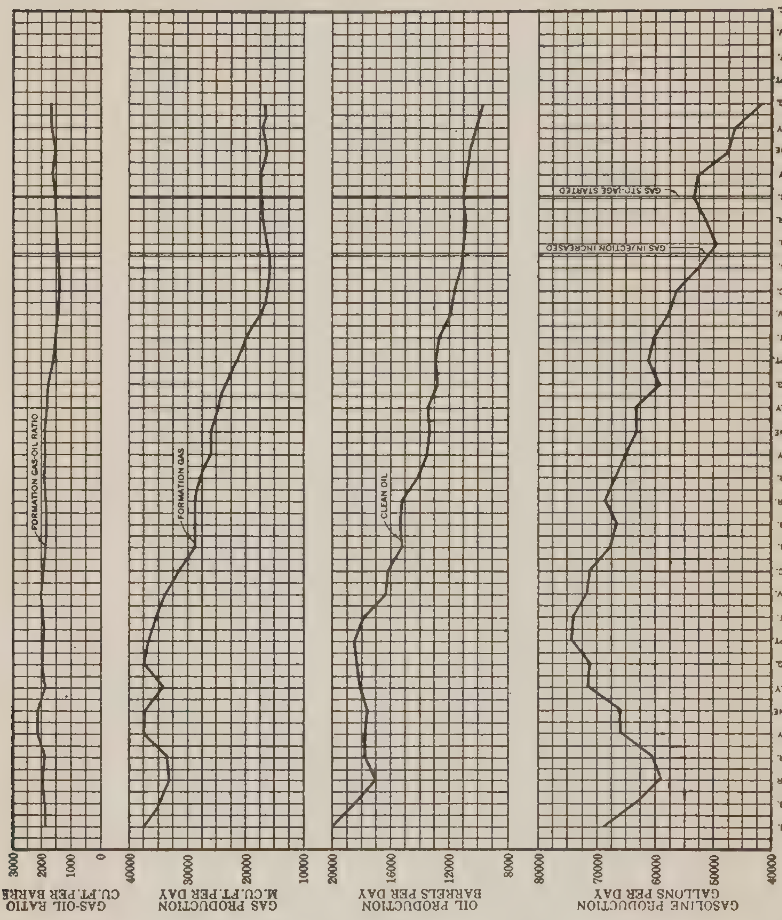

FIGURE 33.—Production graphs for Callendar, Hellman, and Reyes leases, Dominguez field, Calif. (After E. W. Masters)

"Figure 33 is a graph of the oil, gas, and gasoline production, and the formation gas-oil ratios for the Callendar, Hellman, and Reyes leases during 1926, 1927, and up to September 1, 1928. It is interesting to note that although ten wells were taken off production and used as injection wells, 22 wells beaned back, and 4 pumping wells operated

against high back pressure, daily oil production subsequent to initiation of the gas-storage project closely followed the normal oil-decline curve established before gas storage started. Incidentally this proves the effectiveness of repressuring in stimulating the production of oil.

" Figure 33 also shows that when the volume of injected gas was increased by the Union Oil Co. in February, 1928, the field gas production began to increase immediately. With the beginning of the gas-storage project, gas production declined due to the application of back pressure on producing wells. This shows that gas was actually being stored. Injecting large volumes of gas for storage purposes did not affect the field gas-oil ratio. Their control has been possible by careful selection of injection wells and regulation of back pressures in producing wells.

" Gasoline production increased after February, 1928, when circulation of dry gas was increased from 3,000,000 cubic feet to 6,500,000 cubic feet a day but declined after May 1, due to operating the wells to effect gas storage. The gasoline content per thousand cubic feet of gas recovered did not change materially, and the decrease in gasoline production subsequent to initiation of the gas storage project is due entirely to the smaller volume of gas treated daily by the gasoline plants.

"Although the data at hand represent but four months' operation of the gas storage project, they show that in addition to storing large volumes of surplus gas the oil sands are being repressured and as a result ultimate recovery of oil from the reservoir sands will be increased."

STORAGE AND REPRESSURING IN THE BREA-OLINDA FIELD

The gas-storage project of the Union Oil Co. in the Brea-Olinda field in Orange County, Calif., is described by Lake,[28] the substance of the following paragraphs was taken from his report.

Early in 1928 the upper oil zone on the Sterns property (fig. 34) was chosen as particularly adapted for the storing

[28] Lake, F. W., Storage and Repressuring in Brea-Olinda: A report read before the California District Meeting, of the American Petroleum Institute Division of Development and Production Engineering, Los Angeles, September 21, 1928.

of gas. Structurally the upper zone is a southerly dipping monocline, outcropping at the surface in the northern part of the property as a seepage, and lying some 2,500 feet below sea level in the southern part. Figure 34 shows the structural contours (solid lines) on the top of the zone and the outlines of the seepages as they occur at the surface. The zone is composed of conglomerates and coarse sands interbedded with sandy shales, the whole being more porous

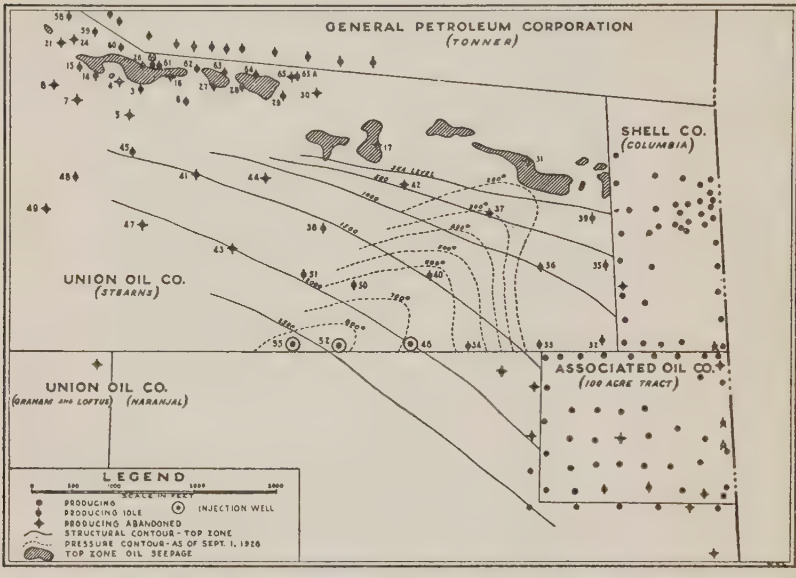

FIGURE 34.—Map of central portion of Brea-Olinda field, Calif., showing pressure contours as of September 1, 1928. (After F. W. Lake)

than is usual in the district. Development took place between 1905 and 1915, although the majority of the wells were completed by 1910. The initial oil production of the wells ranged from 150 barrels daily to as high as 650 barrels of 17 to 23° A. P. I., with very little water production. From June, 1922, to April, 1924, and from May, 1927, to the present the property has been shut in. During their producing life, the wells in the area where storage and repressuring have been carried on have produced a total of 4,050,000 barrels of oil and 2,950,000,000 cubic feet of gas.

When the wells were closed in (May, 1927), the production ranged from 70 barrels to 260 barrels daily. Water encroachment had occurred only in a few wells furthest down the dip and in the more depleted area of close spacing.

Table 13 shows the closed in gas pressure of the wells on April 1, 1928, after being shut in since May 1, 1927. The higher pressures are recorded on the wells further up the dip and further away from the depleted area to the east.

TABLE 13.—CLOSED-IN PRESSURES ON WELLS AFFECTED BY THE GAS-STORAGE PROJECT ON THE STEARNS LEASE IN THE BREA-OLINDA FIELD, CALIF.

Well No.	Closed-in pressures, lbs. per sq. in.					
	April 1	May 1	June 1	July 1	Aug. 1	Sept. 1
55	0	0	760 *	800 *	820 *	830 *
52	0	650 *	740 *	800 *	820 *	830 *
46	0	590 *	590 *	600 *	610 *	680 *
34	30	45	200	350	445	580
33	30	40	70	150	150	150
32	20	20	20	20	20	20
36	30	30	30	30	30	30
40	40	355	450	500	540	620
50	160	200	400	530	560	620
51	0	0	0	0	0	0
38	200	200	200	200	200	200
37	115	130	270	280	280	280
39	35	50	50	50	50	50

* Injection pressures.

The wells showing little or no gas pressure were standing with the fluid levels from 1,200 to 1,500 feet above the zone and showing no gas.

During April, 1928, gas storage was initiated in wells 46 and 52. Pressures in the surrounding wells as of May 1, 1928, after 33,944,000 cubic feet of gas had been pumped in well 46 and 111,000 cubic feet in well 52, are shown in Table 13. The two wells, 40 and 50, lying immediately north of the injection wells showed increases in pressure almost immediately, and toward the end of the month, well 37, lying two locations north and somewhat east of the injection wells,

showed a slight increase in pressure. As indicated by the casing head pressure, the injected gas is moving up the dip and easterly toward the area of maximum depletion.

Pressures on June 1, 1928, after two months of gas injection are also shown in Table 13. It should be noted that wells 40 and 50 continued to increase in pressure as did 37. In addition, the first location east from 46, well 34, has started to show an increase in pressure. During May, gas storage in well 55 was commenced, and up to June 1 (see Table 14) a total of 97,272,000 cubic feet of gas had been stored in the three wells.

On July 1, 1928, the stored gas amounted to 145,738,000 cubic feet. Pressures on all wells so far affected continued to increase, and in addition well 33, two locations east of the injection wells, showed an increase in pressure. The gas migration up the dip had ceased, but the easterly migration continued. During this period, the wells in the closely drilled area to the east were being produced. In order to avoid further easterly migration and to hold the gas on the property the Shell Oil Co. closed in its first two lines of offset wells on July 7, 1928.

Table 14 shows that 209,679,000 cubic feet of gas had been injected in the three injection wells up to August 1, 1928. Northerly and easterly migration had ceased, but all of the wells so far affected showed increases in pressure indicating a compacting of the gas with but little movement out of the immediate area.

Table 13 gives the pressure conditions on September 1, 1928. A total of 315,811,000 cubic feet had been injected up to this time. The pressure necessary for injection in well 55 was too high for the compressor equipment, and very little gas was injected, although the highest safe pressure was maintained on the well. There was no evidence of further gas migration, and the increase in well pressures indicated a further compacting of the stored gas.

During the injection of gas in these wells and the gradual building up of the closed-in pressures, difficulty has been ex-

TABLE 14.—VOLUMES OF GAS INTRODUCED INTO INJECTION WELLS OF THE BREA-OLINDA GAS-STORAGE PROJECT, BREA-OLINDA FIELD, CALIF.

Month	Injection wells						Total volume of gas injected into all wells to end of month, M cu. ft.
	Stearns 52		Stearns 46		Stearns 55		
	Volume of gas injected during month, M cu. ft.	Total volume of gas injected to end of month, M cu. ft.	Volume of gas injected during month, M cu. ft.	Total volume of gas injected to end of month, M cu. ft.	Volume of gas injected during month, M cu. ft.	Total volume of gas injected to end of month, M cu. ft.	
April	111	111	33,944	33,994	......	......	34,055
May	17,052	17,163	40,973	74,917	5,192	5,192	97,272
June	32,023	49,186	7,742	82,659	8,701	13,893	145,738
July	34,565	83,751	22,911	105,570	6,465	20,358	209,679
August	31,636	115,387	74,362	179,932	134	20,492	315,811

perienced in preventing leakage in the old casings and packing heads. As fast as this has occurred, surface cement jobs and repacking have been used to correct the conditions and the wells have been kept reasonably gas-tight. Injection of gas in wells 51 and 38 was attempted, but the casings could not be made sufficiently tight to prevent leakage at the pressures required for the injection of any appreciable quantity of gas. At their normal pressure, however, no leakage occurred.

During the five-month period of gas storage, there was no evidence of passage of stored gas from the property or the area enclosed in the pressure contours. Production from the active wells to the east was not changed. The seepage at the northerly limits of the zone showed no unusual activity, as the oil is asphaltic and relatively immobile except at an increase in temperature considerably above atmospheric conditions. The storage program was being continued (as of September 1, 1928) at the rate of approximately 5,000,000 cubic feet of gas per day. The probability of increased oil recovery and the conservation of 316,000,000 cubic feet of gas which otherwise would have been blown to the air will more than offset the cost of the program; it will be continued until uneconomical pressures are reached or until there is evidence that the stored gas is leaving the property, which does not seem likely.

The storing of natural gas in partly depleted oil-reservoir sands is a conservation measure that has much promise. Although gas storage reservoirs are not available in every oil field, nevertheless many fields now in their flush producing stage some day will be suitable underground containers for large quantities of surplus gas. Information on the storage and withdrawal of natural gas is meager mainly because storage in partly depleted oil sands projects were initiated only a short time ago. The data at hand however substantiate the opinions of many engineers that underground storage of gas is a profitable enterprise.

PART II

THE IMPORTANCE OF NATURAL GAS IN THE CONSERVATION AND PRODUCTION OF PETROLEUM

PHYSICO-CHEMICAL RELATIONS

FOREWORD

Petroleum technologists are agreed that the conservation of gas and gas pressure is of paramount importance in the conservation and economical production of oil. They are further agreed that the physical and chemical laws governing oil production are not yet fully understood. The value of developing pure science as a basis for the newer applied science of the petroleum industry of the future cannot be overestimated. Therefore, the petroleum industry wisely has opened its doors to interested scientists who are carrying on experimental work on problems basic to efficient utilization of gas and gas pressure in the recovery of oil from reservoir sands.

The importance and effect of adsorption; the solubility of gases in petroleum; the Jamin action as effecting the movement of oil and gas through reservoir sands; and the effect of natural gas, occluded or dissolved, upon the viscosity, surface tension, adhesion, and extractability of petroleum, are but a few fundamentals which must be more fully understood in order to be applied intelligently and effectively in the recovery of oil from reservoir sands.

In the following pages of this report, dealing with that branch of science which has for its object the study of the laws governing physical and chemical phenomena, the opinions of various scientists are expressed; in addition published data have been drawn upon freely, because experimental data which are directly applicable to these problems are limited.

Beecher and Parkhurst,[29] Dow and Calkin,[30] and others investigated the solubility of gases in crude oils and found that the amount of dissolved gas in crude oils varied directly as the pressure at any temperature. Thus, with increasing pressures, proportionally larger quantities of gas are held in solution. This agrees with Henry's law that "A given quantity of liquid will dissolve at constant temperature quantities (by weight) of the gas which are proportional to the pressure of the gas."

The following tabulation lists the gravity of the crude oils and the character of the gases used by Beecher and Parkhurst and by Dow and Calkin in their solubility tests.

Curve No.	Character of the gas	Crude oil used, ° A. P. I.		Experimenters
1	Carbon dioxide	Oklahoma	30.2	Beecher and Parkhurst
2	Natural gas No. 1	Oklahoma	35.4	Beecher and Parkhurst
3	Natural gas No. 2	Bradford	44.3	Beecher and Parkhurst
4	Natural gas No. 3	Wyoming	36.0	Dow and Calkin
5	Natural gas No. 3	Oklahoma	31.0	Dow and Calkin
6	Natural gas No. 3	California	25.0	Dow and Calkin
7	Natural gas No. 1	Oklahoma	30.2	Beecher and Parkhurst
8	Natural gas No. 2	Oklahoma	35.4	Beecher and Parkhurst
9	Natural gas No. 2	Oklahoma	30.2	Beecher and Parkhurst
10	Air	Oklahoma	31.0	Dow and Calkin
11	Air	Wyoming	36.0	Dow and Calkin
12	Air	California	25.0	Dow and Calkin
13	Air	Oklahoma	30.2	Beecher and Parkhurst
14	Hydrogen	Oklahoma	30.2	Beecher and Parkhurst

[29] Beecher, C. E., and Parkhurst, I. P., Effect of Dissolved Gas upon the Viscosity and Surface Tension of Crude Oil: A. I. M. E., Petroleum Development and Technology in 1926, p. 53.

[30] Dow, D. B., and Calkin, L. P., Solubility and Effects of Natural Gas and Air in Crude Oils: Bureau of Mines Reports of Investigations, Serial No. 2732, Feb., 1926.

COMPOSITION OF NATURAL GAS USED

	No. 1	No. 2	No. 3
Methane, CH_4	52.0	82.5	98.3
Ethane, C_2H_6	39.0	5.5	0.0
Carbon Dioxide, CO_2	1.2	5.9	1.0
Oxygen, O_2	0.4	0.3	0.0
Nitrogen, N	7.4	5.8	0.7
	100.0	100.0	100.0

The curve numbers refer to the curves shown on Figure 35, which is a graphical representation of certain independent experiments made by these two pairs of experimenters.

It will be noted in the tabulation that Beecher and Parkhurst used one gas (2) that was mainly methane and another (1) that contained a greater percentage of heavier hydrocarbons such as ethane. Dow and Calkin confined their experiments to a " dry " natural gas (3) containing no hydrocarbons which might be considered gasoline vapor.

The amount of gas that will dissolve in crude oil depends upon the character of the gas and the character of the crude oil, if other conditions are constant. A study of Figure 35 shows that carbon dioxide is considerably more soluble in a crude oil than natural gas, and that air and hydrogen are but slightly soluble in crude oil and very much less soluble than natural gas.

A comparison of curves 2 and 8 shows that a natural gas consisting mainly of methane is not as soluble in crude oil as one in which ethane and other heavier hydrocarbons are present. A similar comparison is shown by curves 7 and 9.

That the higher gravity oils dissolve more gas than the heavier oils is shown by a comparison of curves 2 and 7, 3 and 9, and 4 and 6.

Air is only slightly soluble in crude oil, and the results of the experiments performed with air show that the gravity of the oil has no apparent material effect upon the amount of air an oil will hold in solution at a given pressure and temperature.

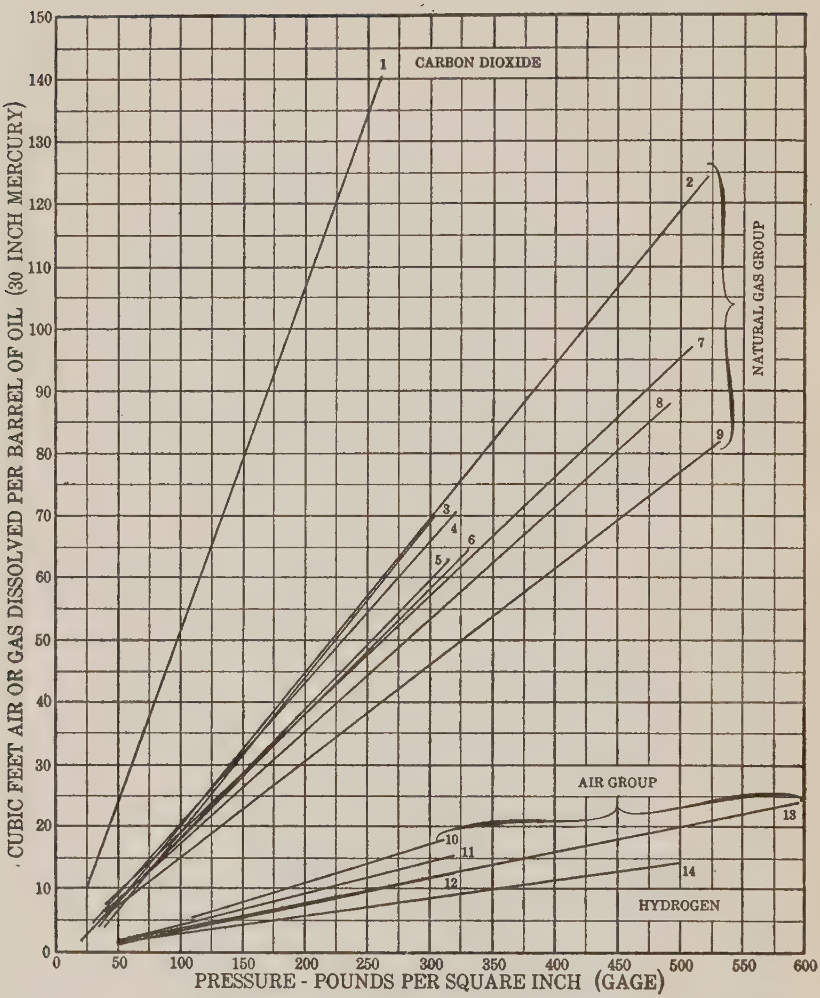

FIGURE 35.—Solubility of carbon dioxide, natural gas, air, and hydrogen in crude oils

TABLE 15.—NUMBER OF CUBIC FEET OF NATURAL GAS DISSOLVED IN 1 BARREL OF SEVERAL CRUDE OILS UNDER VARIOUS PRESSURES

	Salt Creek crude—36° A. P. I. gravity *								Oklahoma and California crudes		
Pressure	70° F.	80° F.	90° F.	100° F.	110° F.	120° F.	130° F.	Actual vol. of gas at 70° F. under pressure noted in col. 1	† Oklahoma 30.2° A. P. I. crude at 70° F.	† Oklahoma 35.4° A. P. I. crude at 70° F.	* California 25.0° A. P. I. crude at 70° F.
	Based on atmospheric pressure—14.7 lbs. per sq. in.								Atmospheric pressure 14.7		
100	20.0	19.3	18.7	18.1	17.5	16.9	16.3	2.56	19.5	24.1	17.4
150	31.5	30.0	28.5	27.8	27.5	26.6	26.0	2.81	29.0	35.7	27.5
200	43.0	41.5	39.2	38.7	37.5	36.3	35.0	2.94	38.5	47.5	38.4
250	54.5	52.0	50.5	49.5	48.1	47.0	45.3	3.02	47.8	59.3	48.0
300	65.7	63.4	61.5	59.8	58.4	57.1	55.7	3.06	57.0	71.0	58.0
350	77.0	74.0	72.0	71.0	70.0	67.0	65.0	3.10	66.7	82.9	68.3
400	88.5	85.3	83.0	81.0	79.2	77.5	75.4	3.13	76.1	94.6	78.1
450	100.0	96.0	94.0	92.4	91.0	87.5	84.8	3.16	85.7	106.3	88.6
500	111.2	107.0	105.0	103.2	101.9	98.0	94.6	3.17	95.0	118.0	98.9
550	122.8	118.0	115.7	114.0	112.0	108.0	104.3	3.19	104.9	130.0	109.0
600	134.0	129.2	126.5	124.6	123.0	118.0	114.3	3.20	114.4	142.0	119.4
650	145.5	140.0	137.5	135.5	133.7	128.0	124.0	3.21	123.9	153.5	129.6
700	157.0	151.4	148.4	146.2	144.1	138.6	134.0	3.22	133.3	165.0	140.0
750	168.0	162.0	159.0	157.0	154.8	148.9	143.8	3.23	143.0	177.0	150.0
800	179.5	173.3	170.0	167.6	165.1	159.0	153.4	3.24	152.3	188.8	160.0
850	191.0	184.0	181.0	178.4	176.0	169.0	163.0	3.25	161.8	200.0	170.0
900	202.5	195.2	191.8	189.0	186.4	179.0	173.0	3.25	171.3	212.2	180.5
950	214.0	207.0	202.0	200.0	197.0	189.0	182.8	3.26	180.5	223.9	190.4
1,000	225.3	218.3	213.0	210.3	207.4	199.2	192.2	3.26	190.0	236.0	200.8

* After Dow and Calkin, Bureau of Mines Reports of Investigations No. 2732.
† After Beecher and Parkhurst, Pet. Dev. & Tech. 1926, A. I. M. E.

ANALYSIS OF GAS USED FOR WYOMING AND CALIFORNIA CRUDES:

Methane	98.30 per cent
Ethane	0.00
Carbon dioxide	1.00
Nitrogen	.70

ANALYSIS OF GAS USED FOR OKLAHOMA CRUDES:

Methane	52.0 per cent
Ethane	39.0
Carbon dioxide	1.2
Oxygen	.4
Residue	7.4

Nowels [31] prepared Table 15, showing the number of cubic feet of natural gas dissolved in 1 barrel of several crude oils under various pressures. This table is based on published data, as may be noted by the footnote references.

Solution of gas in oil is essentially a vapor-pressure phenomenon. The driving force is the difference between the partial pressure of each constituent in the gas and the vapor pressure due to the portion dissolved in the liquid. When this difference is zero, no further solution is possible; in other words, equilibrium has been reached. The solution of each constituent of the gas, such as methane, ethane, propane, etc., goes on independently of the others. In computations involving gas solubility it is absolutely necessary to have a complete analysis of the gas, giving quantitatively the amount of each fraction present.

EQUILIBRIUM RELATIONS

Relation between Molecular Percentage and Volume Percentage

Because the vapor pressure of the solute is proportional to the molecular percentage while practical work is carried out on the basis of volume percentages, a simple relation between the two is desirable.

Given:

$M =$ molecular weight of oil,
$m =$ molecular weight of gas fraction (Table 16),
$x =$ volume percentage of gas fraction,
$100 - x =$ volume percentage of oil,
$D =$ density of oil,
$d =$ density of gas.

To find $S =$ molecular percentage of lighter constituent.

The number of mols present will be proportional to:

$$\frac{xd}{m} \text{ and } \frac{(100 - x)\,D}{M}$$

[31] Nowels, K. B., Supervising engineer, petroleum field office, Bureau of Mines, Laramie, Wyo.

Therefore:

$$S = \frac{100\,\frac{xd}{m}}{\frac{xd}{m} + \frac{(100 - x)\,D}{M}}$$

$$S = \frac{100x}{x\left(1 - \frac{Dm}{dM}\right) + \frac{100\,Dm}{dM}}$$

Usually the first term in the denominator may be neglected, giving:

$$S = x\,\frac{dM}{Dm}.$$

This gives for r, the ratio between molecular and volume percentage, the simple relation

$$r = \frac{dM}{Dm}.$$

Since the vapor pressure of the solute is proportional to the molecular saturation, the smaller r becomes, the higher will be the solubility on the volume basis. Since the molecular weights of oils decrease much more rapidly than their densities, it follows that the solubility of natural gas is greater in light than in heavy oils. This solubility relation indicates that gas-oil ratios theoretically should be lower in producing heavy crudes than lighter gravity oils, and restoration of pressure should require less gas for a given amount of oil sand in heavy oil districts than in light oil districts.

Exact mathematical discussion of the mechanism of solution appears to be out of place in dealing with crude oils and natural gases as found in nature, since much of the necessary data for such investigation cannot be determined with accuracy.

Devine,[32] in discussing various methods of determining molecular weights of petroleum oils, stated: "The im-

[32] Devine, John M., U. S. Bureau of Mines, The Determination of Molecular Weights of Nonvolatile Petroleum Oils: Paper read before Oklahoma Academy of Science, Stillwater, Okla., Nov. 30, 1928.

portance of determination of molecular weights, or, more truly, of average molecular weights, has not been recognized as extensively in investigative work on petroleum as is justified. This has been due partially to inability to obtain results in which the investigator could place full confidence. . . . . At best, the status of molecular-weight determinations in relation to heavier petroleum oils is unsatisfactory; and if these oils are considered to be isocolloidal in character, it is easy to understand that the question of methods and technique is not the only obstacle in the way of successful solution of the problem."

Certain experimenters have determined that the molecular weight of California petroleum oils is roughly:

$$\text{Mol. Wt.} = \frac{58}{1.088 - \text{Sp. Gr.}} - 64.$$

This formula, however, is valid only for oils having specific gravities varying from 0.6 to 0.95.

The molecular weights and other physical properties of the major constituents of natural gases are given in Table 16.

TABLE 16.—PROPERTIES OF HYDROCARBONS OCCURRING IN NATURAL GAS
(For use in solubility calculations)

	Formula	Molecular weight	Boiling point, ° F.	Critical temp.,* ° F.	Critical pressure,* lbs. per sq. in.	Specific gravity liquid, water = 1
Methane ...	CH_4	16	—256	—139.9	736.5	0.415
Ethane	C_2H_6	30	—119.4	+ 95.0	665.8	.446
Propane ...	C_3H_8	44	— 47.4	206.5	662.8	.536
Butane	C_4H_{10}	58	+ 32.5	307.5	522.0	.600
Pentane ...	C_5H_{12}	72	97.7	387.0	486.6	.6337
Hexane	C_6H_{14}	86	156.2	454.1	441.9	.6678

* Day, David T., Handbook of the Petroleum Industry, 1922, p. 730.

RATE OF SOLUTION OF GAS IN CRUDE OIL

All gases dissolve very slowly in crude oil, unless the oil is violently agitated or so distributed as to expose a very

large surface per unit of volume; in other words, the rate of diffusion of gas in solution through oil is very slow. Solution of gas in oil distributed in thin films over sand grains, as in partly depleted oil sands, would be rapid. Since conditions in an underground reservoir could never be known with sufficient accuracy to permit reasonably satisfactory calculations of probable solution rates, the above general statement seems to be all that is likely to have immediate application in the study of restoration of gas pressure.

Certain studies of the Lance Creek field, Wyo., seem to bear out the conclusion that the amount of natural gas taken from this field is at least double the amount that can be accounted for by the known solubility of gas in crude oil and the existing pressure of the gas, even when a factor of 1.4 was used because of the deviation of gases from Boyle's Law. The data upon which the above conclusion is based were studied later by Germann,[33] and his conclusions regarding the apparent discrepancy between the volume of gas produced and that originally in solution in the oil in the reservoir sands are given here:

"The gravity of the oil in the Lance Creek field is about 44° B., and the original pressure was 80 atmospheres. The experiments on the solubility of gas in oil which were performed and upon which the above conclusion was drawn, were made on oil of a higher density than 44° B. Not being in possession of the figures, it is impossible to state what error in calculations this would involve. However, the solubility of a gas in oil increases tremendously as the oil becomes lighter. Assuming no great error was made in the volume of sand and free space or voids estimate, it is easily conceivable that the lighter Lance Creek oil would dissolve enough extra gas to account for the discrepancy.

"If such an explanation is not proved to be correct, we may be forced to take recourse to certain well-known phenomena of colloid chemistry. It has long been known that gases concentrate on surfaces to a surprising extent. These facts are easily demonstrated by the following experiment.[34]

[33] Germann, Dr. Frank E. E., University of Colorado, Boulder, Colo.
[34] See paper by Germann, page 216.

If a glass vessel is evacuated so as to show zero residual pressure, and then allowed to stand, a small pressure will again be recorded after several hours. If this is pumped out and allowed to stand, a pressure will again be established, but smaller than the former. In other words, a first guess would be that the container or stopcock had a leak. This is, however, not the case, as ultimately the vacuum will be maintained. This can be brought about more quickly if the container is heated, as heat favors the removal of the gas at the surface. By careful measurements of the volume of gas which can be taken from the surface by successive evacuations, and by measurements of the area of the container, we are in a position to know something of the density of the gas at the surface. If we set an upper limit to the thickness of this film, we can calculate the volume, and accordingly, the density of the gas. There are certain definite experiments which prove to us that the thickness cannot be greater than the figures we use. By means of these calculations we find that air has a density of the order of liquid air at the surface of glass. This is true in spite of the fact that both oxygen and nitrogen have critical temperatures far below room temperature. The critical temperature of oxygen is — 118° C., or — 180° F., while that of nitrogen is — 146° C., or — 231° F. It will be remembered that the critical temperature is that temperature above which no amount of pressure can bring about liquefaction.

"This general property of the concentration or condensation of gases at the gas-solid interface is referred to as adsorption, and plays an enormous rôle in chemical as well as physical processes. It is the controlling factor in the phenomenon we call catalysis as used in the production of sulfuric acid, the hardening of oils, etc.

"Certain very fine powders when placed in a tube will flow from end to end like water. If the tube be evacuated, taking care to remove the last traces of gases as described above, the powder no longer flows. If we attempt to restore the powder to the original condition of "fluidity," by readmitting air, we find that it remains in a caked condition. Agitation of the caked powder in the presence of air will, however, re-establish the fluid property.

"During the process of evacuation, the volume of the powder decreases very materially, the original volume being largely gotten back on agitation with air. It is thus

seen that we have a direct evidence of a film of a certain finite thickness about each grain, and it is this film which makes the powder flow like water.

"Adsorption of gases on the surface of solids is a specific property; that is, the amount of gas adsorbed at a given pressure and temperature depends both on the nature of the gas and on the nature of the solids. Adsorption increases with increase of pressure, but decreases with increase of temperature. The amount of adsorption can thus only be determined by experiment, attempting to reproduce the original conditions.

" In the above only one set of conditions for adsorption has been described, that of a solid adsorbing a gas. In the same way, we have solids adsorbing liquids, liquids adsorbing liquids, liquids adsorbing gases, solids adsorbing solids, etc. In the case of natural gas in oil-gas sands, we may have the gas adsorbed by the sand (silica), in case the sand is clean and dry. If, however, the sand is covered with a film of oil saturated with gas, the sand-oil mixture still having voids, then we would have to consider a condition of gas adsorbed by a liquid, as the gas would not displace the oil from the sand.

" It is obvious from what has been said that it would be impossible to reproduce the original conditions in an oil field which has been allowed to lose its gas. In other words, repressuring, even with the same kind of gas, will not necessarily be successful. The reason for this is the same as was described above in the attempt to restore the powder to the condition in which it had been originally. Merely readmitting the air did not suffice, but agitation in the presence of the gas was necessary. This is obviously an impossibility in the case of oil sands.

" The apparently great success which has been achieved by compressing the easily condensable gases, propane, butane, and pentane, into certain key wells, could have been predicted, and is substantiated by theory. In crude oil, we have several series of closely related organic substances. The properties of any two adjacent members of a series are very similar. The farther apart the members of a given series, the greater the difference in properties. Thus the solubility of methane, ethane, and propane in a heavy oil is less than the solubility of butane, pentane, etc. Moreover, these gases are normally liquid under moderate pressures,

and may flow about in the interstices of the sand, whereas the methane and ethane depend on being close to a surface in order to have densities comparable to liquids. They are, therefore, not free to move about.

" The fact that the oil has dissolved a goodly share of the easily condensable gases not only cuts down the viscosity, but also favors the solution of more of the methane and ethane which may still be present underground. The latter would cut down the viscosity still more.

" The natural tendency of an oil blowing off gas on releasing pressure would be for the gas-oil ratio to decrease, but experience shows the contrary to be true. The most logical explanation of this would be that the gas ' blows through.' Under the conditions of oil in sand, as contrasted to a pool of pure oil, blowing through is easily possible and can be reproduced in the laboratory. It appears, therefore, that in repressuring much better results would be achieved if no pumping were done until the entire field has been repressured. The gas would have time to dissolve in the oil, would cut down the viscosity, and would not be so apt to blow through. It might also be mentioned that blowing through is more probable in a viscous than in a thin fluid.

" It is of interest to point out that, although the adsorbed gas may be in a state similar to liquids, still it is in no sense possible for it to act as a free liquid, since it depends on its proximity to a surface for its particular properties. It would therefore have no effect on any of the properties of the oil which completely fill sand voids. This latter we might call oil in bulk, as distinguished from oil which has a surface exposed to the gas phase. It is only the oil in bulk which flows in sands, the other oil adhering to the sand being lost because of the gas by-passing it. The only way the oil not in bulk can be reclaimed is by washing it out, in a sense, with the easily condensable gases.

" Adsorbed gas has a very low vapor pressure, but it has no effect on the vapor pressure of the oil. This latter is controlled by the amount and type of gas in solution."

Effect of Temperature on Solubility of Gas in Oil

The effect of temperature on the equilibrium between free gas in contact with oil and dissolved gas may be calculated from vapor-pressure curves if the composition of the oil and

gas are known. This process, however, is too complex for practical application, and the effect of temperature is best determined by actual tests of the oil and gas under consideration.

Laboratory experiments show that the quantity of gas that will dissolve in crude oil depends upon the temperature, other conditions remaining constant. Typical results of a few such tests are summarized in Table 17 and illustrate the effects to be expected by changes in temperature through the range likely to be found in practical work.

TABLE 17.—THE SOLUBILITY OF A NATURAL GAS, BY VOLUME AT ATMOSPHERIC PRESSURE, IN SEVERAL CALIFORNIA CRUDES (VOLUME OF GAS DISSOLVED IS EXPRESSED IN PER CENT)

Source of crude	Nature of crude	Gravity of crude, °A. P. I.	Temperature, °F.		
			85°	105°	125°
San Joaquin Valley....	Light	28.7	70%	67%	63%
Southern California...	Light	26.0	71	67	63
Southern California...	Heavy	20.8	59	53	51
San Joaquin Valley....	Special	20.8	60	56	55

ANALYSIS OF THE GAS

	Per cent
Specific gravity (Air = 1)	0.719
H_2S	.5
CO_2	.8
"Illuminants"	1.9
O_2	.8
CO	.2
N_2	2.4
Combined hydrocarbons (chiefly CH_4)	93.4

For example, Beecher and Parkhurst, in work cited previously, found that at a pressure of 400 pounds per square inch and a temperature of 90° F., approximately 75 cubic feet of gas was dissolved in a barrel of oil, whereas at a temperature of 110° F., 70 cubic feet of gas was dissolved in the same oil.

The effect of underground changes in temperature upon the oil-gas equilibrium cannot be great, since no very rapid

temperature changes in oil sands can be expected. Cooling of oil by expansion of gas in passing from higher to lower pressure regions can be only slight, because the masses of rock and liquid to be cooled are too large to be affected perceptibly by the small amount of heat taken from them by the relatively small weight of gas which is associated with the oil.

Warming of an oil sand might take place by invasion of hot salt water as the oil is produced. There would be in this case an increased rate of release of gas from solution at the edge of the advancing water, but this would evidently not be noticeable in a practical sense, because the advance of the water is very slow.

EFFECT OF DISSOLVED GAS ON THE PHYSICAL CHARACTERISTICS OF CRUDE OIL

VISCOSITY

The viscosity of a crude oil is reduced when the oil contains gas in solution. The decrease in viscosity depends, if other conditions are constant, upon the amount of gas dissolved in the oil. When a Panhandle, Tex., crude of 36.6° A. P. I. was saturated with a 98 per cent methane gas at a pressure of 260 pounds per square inch and at 73° F., the viscosity decreased from 190 to 106 seconds (Saybolt), or 45 per cent. Beecher and Parkhurst[35] found that by saturating a given crude with natural gas at a pressure of 500 pounds per square inch and 70° F., the viscosity was decreased 50 per cent. At a pressure of 1,800 pounds—a reservoir pressure corresponding to a depth of approximately 4,100 feet—sufficient gas may dissolve in the oil to reduce the viscosity until it equals that of kerosene.

Table 18 summarizes the work of various investigators on the effect of different gases on the viscosity of petroleum. Only a few pressures have been given in each case, as it has been found that the volume of the various gases dissolved

[35] *Op. cit.*

follows Henry's law very closely, except for a very condensable gas, as, for example, weathering-plant gas. The data obtained by the various investigators are not strictly comparable, because of differences in the materials and apparatus used, and the conditions maintained during the tests.

A study of Table 18 reveals the superiority of dissolved gas over certain other gases for reducing the viscosity of crude oil, hence aiding in its recovery from the sands. Emphasis is thus placed on the desirability of using natural gas as far as possible for repressuring, and particular emphasis is placed on the desirability of utilizing to the utmost the gas occurring naturally with the oil.

It is interesting to note that flue gas behaves in much the same manner as air. This fact may in a general way solve the problem raised in the following excerpt of a letter report supplied by Bureau of Mines engineers. "A rather difficult problem has developed in the Alluwe district, Okla., which has been using air as a repressuring medium. It appears that the return gas from the producing wells is no longer fit for combustion and power purposes. Analysis shows that this gas contains from 50 to 77 per cent nitrogen, from 3 to 6 per cent oxygen, and from 1 to 7 per cent carbon dioxide. Apparently the oxygen in the air reacts with some of the underground elements, either the oil, the cementing material in the sand, or carbonated water, and as a result it not only increases the cost of operation through the necessity of having to pipe in natural gas for power purposes but also has an important bearing on the technical problems of recovering the oil from the sand. As the injected air no longer remains there, the problem of propelling oil in sand resolves itself in part into an investigation of the effect of these various mixtures, nitrogen, carbon dioxide, and oxygen, as propulsive agents."

Since the gas reported as coming from the producing wells in the Alluwe district, Okla., is not materially different in composition from flue gas, which has been proved to

TABLE 18.—EFFECT OF VARIOUS DISSOLVED GASES ON THE VISCOSITY AND VOLUME OF PETROLEUM

Source of petroleum	Gravity, °A. P. I.	Gas used	Gravity of gas (Air = 1)	Pressure, lbs. per sq. in.	Temp., °F.	Viscosity		Volume		Investigator *
						Saybolt sec.	Variation, per cent	C. c.	Variation, per cent	
Salt Creek, Wyo..	37.4	Air	1.00	Atmosphere	100	44.0	.....	210	.....	M. R. Co.
				50		42.7	— 2.9	205	— 2.4	
				150		43.7	— 0.7	202½	— 3.6	
				250		44.9	+ 2.0	203	— 3.4	
Salt Creek, Wyo..	37.4	Fuel gas	0.98	Atmosphere	100	44.0	.....	200	.....	M. R. Co.
				50		39.6	—10.0	199	— 0.5	
				150		35.3	—20.0	205	— 2.4	
				250		32.2	—27.0	211	+ 5.5	
Salt Creek, Wyo..	37.4	Flue gas	1.035	Atmosphere	100	44.0	.....	210	.....	M. R. Co.
				50		45.8	+ 4.1	203	— 3.3	
				150		47.4	+ 8.0	202½	— 3.6	
				250		49.7	+13.0	202	— 3.8	
Salt Creek, Wyo..	37.4	Carbon dioxide	1.528	Atmosphere	100	44.0	.....	200	.....	M. R. Co.
				50		43.2	— 0.2	197	— 1.5	
				150		40.8	— 7.3	198	— 1.0	
				250		37.7	—14.3	200	.....	
Salt Creek, Wyo..	37.4	Weathering-plant gas	1.52	Atmosphere	100	44.0	.....	200	.....	M. R. Co.
				50		26.4[a]	—40.0[a]	224	+ 11.2	
				100		20.4[a]	—54.0[a]	272	+ 36.0	
				200		19.0	—57.0	480	+140.0	
Wyoming	19.4	Air	1.00	Atmosphere	100	550	.....	[b]	[b]	D. & C.
				50		655	+19.0	...	.....	
				150		[c]	[c]	...	.....	
				250		[c]	[c]	...	.....	

* M. R. Co., Midwest Refining Co. D. & C., Dow and Calkin. B. & P., Beecher and Parkhurst. M. & H., Mills and Heithecker.

[a] These two results are not corrected for increase in head due to condensation, but the result for 200 pounds pressure is so corrected.

[b] Dow and Calkin recorded some data on the volume effect of dissolved methane. See Solubility and Effects of Natural Gas and Air in Crude Oil: Bureau of Mines Serial 2732, Feb., 1826, p. 9.

[c] Dow and Calkin's curves are not extended to cover the results for these pressures.

[d] Mills and Heithecker recorded data also on decreases of volume and A. P. I. gravity due to the diminution of pressures. See Volumetric and A. P. I. Gravity Changes Due to the Solution of Gas in Crude Oil: Bureau of Mines Serial 2893, Oct., 1928, p. 12.

TABLE 18.—EFFECT OF VARIOUS DISSOLVED GASES ON THE VISCOSITY AND VOLUME OF PETROLEUM (*Continued*)

Source of petroleum	Gravity, °A. P. I.	Gas used	Gravity of gas (Air = 1)	Pressure, lbs. per sq. in.	Temp., °F.	Viscosity		Volume		Investigator *
						Saybolt sec.	Variation, per cent	C. c.	Variation, per cent	
Wyoming	19.4	Natural gas	0.567	Atmosphere	100	550	.....	...	.....	D. & C.
				50		473	—14.0			
				150		[c]	[c]			
				250		[c]	[c]			
Oklahoma	35.4	Natural gas	0.786	Atmosphere	100	.....	.....	...	.....	B. & P.
				50			— 8.0			
				150			—22.0			
				250			—28.0			
Oklahoma	33.3[d]	Natural gas	.....	Atmosphere	70	60	.....	...	[d]	M. & H.
	34.6			200					1.49	
	35.9			400					2.88	
	37.2			600					4.38	
	38.5			800					5.82	
	39.8			1,000					7.30	
Oklahoma	41.4[d]	Natural gas	.....	Atmosphere	70	44	.....	...	[d]	M. & H.
	42.9			200					1.72	
	44.1			400					3.47	
	45.4			600					5.20	
	46.8			800					6.97	
	48.1			1,000					8.70	
California	21.1[d]	Natural gas	.....	Atmosphere	70	431	.....	...	[d]	M. & H.
	22.0			200					1.10	
	22.9			400					2.15	
	23.8			600					3.23	
	24.7			800					4.30	
	25.6			1,000					5.42	

* M. R. Co., Midwest Refining Co. D. & C., Dow and Calkin. B. & P., Beecher and Parkhurst. M. & H., Mills and Heithecker.

[a] These two results are not corrected for increase in head due to condensation, but the result for 200 pounds pressure is so corrected.

[b] Dow and Calkin recorded some data on the volume effect of dissolved methane. See Solubility and Effects of Natural Gas and Air in Crude Oil: Bureau of Mines Serial 2732, Feb., 1926, p. 9.

[c] Dow and Calkin's curves are not extended to cover the results for these pressures.

[d] Mills and Heithecker recorded data also on decreases of volume and A. P. I. gravity due to the diminution of pressures. See Volumetric and A. P. I. Gravity Changes Due to the Solution of Gas in Crude Oil: Bureau of Mines Serial 2893, Oct., 1928, p. 12.

behave much the same as air, it is evident that the propulsive effect of the products formed underground will not behave in a way materially different from air. This brings up an interesting question of the selection of a gas for the gas drive. The use of air leads to the possibility of explosive mixtures of combustible gas and oxygen in the gases coming from the producing wells. In many fields, no doubt, flue gas is available which could be placed in condition for use for drive purposes. The use of flue gas low in oxygen would eliminate the possibility of explosive mixtures and would in a large measure eliminate the possibility of corrosion of casing and tubing in the producing wells.

Decreasing the viscosity of crude oil reduces the frictional resistance to flow. Beecher and Parkhurst [36] say that "Viscosity is the most important physical characteristic of crude oil which affects the rate of flow through small irregular openings of a sand. The quantity of oil that will flow through openings is inversely proportional to the viscosity, other conditions remaining constant, while the pressure required to produce a given flow varies directly as the viscosity. For example, if the viscosity of the oil should be reduced 50 per cent, twice as much would flow through the sands if other conditions remain constant, or one-half of the pressure would be required to force an equal amount through the sand."

Air has been repeatedly shown to increase the viscosity of asphaltic-base California crude oil, probably by oxidation of some of its constituents. There is little doubt that air in true solution would decrease the viscosity, and that it is actually increased is evidence of oxidation. Dow and Calkin [37] bubbled pure oxygen through a sample of heavy California crude for 7½ hours, and found that the viscosity had increased from 577 to 607 seconds (Saybolt Universal).

[36] *Op. cit.*
[37] *Op. cit.*

A rather similar oxidation is brought about when air is blown through the hot residue from stills in order to convert them into petroleum asphalt. A variation in effect of air from oil to oil is easily attributed to the variable susceptibility to oxidation.

Table 19 was prepared by Nowells [38] and shows for several crude oils the percentage reduction in viscosity caused by small amounts of natural gas and air in solution.

The effect of temperature on the viscosity of petroleum has been studied by Eckart,[39] and he has demonstrated that the relation between absolute viscosity and temperature, when plotted on double logarithm scales, shows a close approximation to a straight line, at least over the working range of temperatures for which the oil retains its identity. At high temperatures the more volatile constituents will begin to vaporize, and at very low temperatures certain constituents will begin to solidify and separate out, in this way changing the character of the oil itself. Between these limits of temperature, however, it has been shown by a large number of tests that, within the range of observational error, the logarithmic straight-line relation may be assumed to hold. Since frictional resistance is a function of absolute viscosity, the effect of temperature on frictional resistance may be calculated.

Analysis of samples of the crude oil from the First and Second sands, Salt Creek field, Wyo., shows that the gravities of the oil from the two sands vary less than 1° (see Table 20). There is, however, a considerable difference in the viscosity of the two oils at low temperatures, but at the temperatures existing in the wells, which in the Salt Creek field are slightly above 100° F., the viscosities of the two oils are approximately the same.

[38] *Op. cit.*

[39] Eckart, William R., former professor of mechanical engineering, Stanford University, Palo Alto, Calif.

Table 19.—Percentage Reduction in Viscosity of Several Crude Oils Caused by Small Amounts of Natural Gas and Air in Solution

Cu. ft. gas or air per bbl. of oil in solution	Percentage decrease in viscosity					Percentage increase in viscosity	
	Gas No. 1				Gas No. 2	Air	
	Wyo.* crude, 550 sec. at 100° F.	Cal.* crude, 577 sec. at 100° F.	Cal.* crude, 284 sec. at 100° F.	Okla.* crude, 68 sec. at 100° F.	Okla.† crude, 30.2 A. P. I.	Wyo.* crude, 550 sec. at 100° F.	Cal.* crude, 577 sec. at 100° F.
1	1.8	1.1	1.3	0.5	1.0	4.0	3.0
2	3.5	2.0	2.5	1.0	2.0	8.0	6.5
3	5.2	3.0	3.6	1.4	2 8	12.0	9.8
4	6.9	4.0	4.8	1.8	3.6	16.1	
5	8.5	5.0	6.0	2.5	4.5		
6	10.0	5.7	7.0	2.7	5.3		
7	11.6	6.7	8.4	3.1	6.2		
8	13.4	7.8	9.4	3.5	7.0		
9	15.0	8.7	10.6	4.0	7.6		
10	16.7	9.6	11.7	4.4	8.4		
11	18.4		13.0	4.7	9.0		
12			14.0	5.2	9.8		
13			15.1	5.6	10.5		
14			16.3	6.0	11.2		
15			17.5	6.5	11.8		
16			18.6	6.8	12.5		
17				7.3	13.1		
18				7.7	13.8		
19				8.3	14.4		
20				8.6	15.0		
21				9.0	15.5		
22				9.4	16.1		
23				9.8	16.7		
24				10.3	17.2		
25				10.6	17.6		
30				12.7	20.2		
35					22.7		
40					25.2		
45					27.6		
50					30.0		

* After Dow and Calkin, Bureau of Mines Reports of Investigations, Serial 2732.

† After Beecher and Parkhurst, Pet. Dev. & Tech. 1926, A. I. M. E.

ANALYSIS OF GAS NO. 1

	Per cent
Methane	98.30
Ethane	0.00
Carbon dioxide	1.00
Nitrogen	.70

ANALYSIS OF GAS NO. 2

	Per cent
Methane	52.0
Ethane	39.0
Carbon dioxide	1.2
Oxygen	.4
Residue	7.4

The initial boiling point of the Second sand oil, Salt Creek field, Wyo., has increased perceptibly with the decline in formation pressure. In 1922 it averaged about 98 to

TABLE 20.—TYPE ANALYSIS OF CRUDE OIL FROM FIRST AND SECOND WALL CREEK SAND WELLS, SALT CREEK FIELD, WYO.

	First sand	Second sand
Gravity, °A. P. I.	38.3	37.7
Sulfur, per cent	0.21	0.12
Cold test, °F.	58	42
Viscosity (Saybolt Universal)		
at 40° F., seconds	Too much wax	Too much wax
50°	" " "	" " "
60°	260	175
70°	89	74
80°	55	53
90°	45	45
100°	42	45
Initial boiling point (sea level), °F.	130	130
Per cent off at		
158° F. (sea level)	1.0	2.0
221°	6.6	7.4
284°	14.8	16.4
374°	27.2	27.2
500°	39.8	40.6
600°	46.2	54.0
700°	....	69.6

103° F.; 116° F. in 1924; and 142 to 145° F. in July, 1926. Boiling points are controlled largely by the amounts of light gaseous fractions held in solution in the oil; as these are withdrawn, the boiling point rises.

CHANGE IN VOLUME OF PETROLEUM DUE TO DISSOLVED GASES

Experiments [40] made in the Bureau of Mines laboratories on a sample of Bartlesville crude saturated with natural gas at a pressure of 1,000 pounds per square inch at 70° F., showed a volume increase of over 7 per cent due to dissolved gas. Similar tests on a sample of Seminole oil showed an

[40] Mills, R. Van A., and Heithecker, R. E., Volumetric and A. P. I. Gravity Changes Due to the Solution of Gas in Crude Oil: Bureau of Mines Reports of Investigations, Serial 2893, September, 1928.

increase in volume of 8.7 per cent. The experiments on different oils showed that the volumes increased in direct proportion to the pressures, giving straight-line relationships; but equal amounts of gas dissolved in different oils did not give equal volume changes. The experiments also showed for the different oils that decided increases in A. P. I. gravity occurred concurrently with the increases in volume (see Table 18). Upon the liberation of gas from solution, when pressures were reduced, decided decreases in volume and A. P. I. gravity of the oils were found to take place.

The data given in Table 18 indicate that in most cases no material increase in volume results upon the introduction of gas into crude oil at pressures up to 250 pounds per square inch. Above this pressure some of the volume-increase percentages are quite noticeable. The most notable is weathering-plant gas, which began to condense under very moderate pressure, and upon which full pressure could not be placed because of rapid condensation.

In regard to the change in volume due to dissolved gas, there is one factor which has not been taken into account in some of the data shown in Table 18. Toward the end of the Midwest Refining Co.'s experiments it was found that petroleum is measurably compressible and that the compressibility was roughly of the order of 0.06 per cent for each pressure increase of 50 pounds per square inch. Neglecting this correction leads to an erroneous assumption that decrease in volume of oil takes place upon introducing gas under pressure.

SURFACE TENSION

The surface tension of crude oil is reduced by dissolved gas. Beecher and Parkhurst[41] saturated two different crudes with gas at pressures of 400 to 500 pounds per square inch and found the surface tension reduced 20 per cent. This phenomenon has a practical value in oil recovery work.

[41] *Op. cit.*

The relation between surface tension and recoverable oil as summarized by the experimenters mentioned is as follows: " A large percentage of oil which present production methods fail to remove from the sands is held by capillarity. As the gas dissolved in the oil escapes, the surface tension is increased and, likewise, the capillary force which is a measure of the surface tension. If this increase in surface tension could be prevented during the process of extracting oil from the sands, a greater volume of oil should be recovered."

Francis and Bennett[42] have investigated the surface tensions of crude petroleum and found that the surface tension is a linear function of the temperature, decreasing approximately 0.05 dynes per centimeter for each degree Fahrenheit rise in temperature. They found also that surface tension was a linear function of the density.

The change in surface tension with temperature will also affect the capillarity, but to what extent is unknown, as the adhesiveness has been shown to have a concurrent effect in determining capillarity. It would seem very probable that capillarity is directly proportional to the temperature of the oil.

RELATIVE ADVANTAGES OF VARIOUS GASES FOR PRESSURE MAINTENANCE OR RESTORATION

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The pumping of gas into an oil bearing formation has many possible advantages in maintaining or rebuilding the rock pressure. Pressures as high as those originally found should be maintained wherever possible, in order to avoid excessive separation of gas and oil in the sands. If separa-

[42] Francis, C. K., and Bennett, H. T., The Surface Tension of Petroleum: Jour. Ind. and Eng. Chem., vol. 14, July, 1922, pp. 626-628.

tion is allowed to take place, additional resistance to flow results, due to formation of bubbles in the oil and to an increase of the viscosity and surface tension of the oil. Where the rock pressures have been allowed to decrease, however, it is still possible to improve underground conditions, which will aid in the recovery of oil. Instead of forcing only enough gas into the structure to maintain the existing pressure, the quantity of gas may be increased gradually, and the rock pressure slowly brought up to more favorable values.

The advantages resulting from this restoration of pressure are of two kinds. The increased gas pressure furnishes more energy to be used in forcing oil toward the well inlet; this effect should become apparent almost as soon as the pressure increase is achieved. The other result has to do with changes in the properties of the oil existing in the sands, caused by passage of the gas into solution. As gas dissolves, the surface tension and viscosity of the oil decrease, thus permitting more complete drainage from the capillary pores of the sand and easier flow through the greater part of the formation, where viscous flow probably takes place. These advantageous conditions will result only in so far as the amount of gas in solution is increased.

The fundamentals of the process of dissolving a gas in a liquid have been studied by scientists. When a gas is brought into contact with a liquid, molecules of gas pass into the interface and dissolve in a very thin surface film of liquid. As this process continues, the concentration of dissolved gas molecules in the surface film increases gradually until the rate at which dissolved gas molecules pass back into the gas space just equals the rate at which molecules enter solution. When this condition is reached an equilibrium has been established, and the surface layer of liquid has become "saturated" with gas. Of course, the dissolved molecules may not only go back into the gas phase from the surface layer, but they may also wander back into the main body of the liquid. As this latter process takes

place, the concentration of dissolved gas molecules in the main body of liquid increases while that in the surface film decreases, which in turn allows more molecules to enter from the gas phase. It is easily seen that saturation of the entire body of liquid can take place only by a combination of these two processes, and that the time required depends upon the slowest step.

The saturation concentration depends upon the natures of the liquid and the gas, upon the temperature, and upon the partial pressure of the particular gas under consideration. Higher temperatures give lower solubilities, while higher pressures of the gas give greater solubility.

The process of moving dissolved gas molecules away from the surface film and into the rest of the liquid can take place in two ways. One way, called diffusion, is the result of the movement of individual molecules, the natural thermal motion, which is of a random nature and comparatively slow. The rate of diffusion through the liquid depends upon the concentration gradient in the direction of movement, the temperature, the size of the molecules, and the viscosity of the liquid. It is evident that at the beginning of the process a relatively high concentration gradient may exist between the surface film and the liquid behind it. However, as the concentration increases in the body of the liquid the diffusion process will become slower and slower, until it finally ceases when the entire body of liquid is saturated. The second migration method is by means of currents or mass movements within the liquid. These currents may result from convection, mechanical agitation, or other causes, and in general are much more rapid in their distributing action than is diffusion.

For petroleum in its fine-grained sand formation there is very little likelihood of aid from the mass distribution process, due to the viscosity of the liquid and the restraining effect of the sands. This leaves the diffusion process to carry on the task, and, again due to the viscosity of the liquid, it is likely to be very slow. Movement of the gas into

the body of the oil will take place more rapidly when the solubility of the gas is high, when the thickness of the liquid body is small, and when the viscosity of the liquid is low. From this reasoning the gas which should be most effective from the point of view of repressuring should be very soluble in petroleum and should lower its viscosity to a large extent. From other considerations, it should be available where needed, cheap, without harmful effect on oil or natural gas, stable, without harmful effect upon oil field equipment, and with a tendency to lower the surface tension of the oil.

Only a few gases will pass the requirements of cheapness and availability where needed. Air is the only gas which meets these two requirements under all conditions; natural gas, and carbon dioxide-nitrogen mixtures resulting from combustion, depend upon the location and condition of the fields. These three gases, in ranging degrees, meet the other requirements previously mentioned.

Natural gas consists mainly of methane and ethane with smaller percentages of other hydrocarbons of higher molecular weight, nitrogen, and other gases. The percentage composition varies with locality and condition of production. A gas containing larger proportions of the more easily condensable higher hydrocarbons is classed as a " wet gas," while one consisting very largely of methane and ethane is called " dry." When available, a wet natural gas is probably the most desirable gas for repressuring operations. It is more soluble than dry gas and reduces viscosity to a greater extent. Its use introduces no new gases to the formation and it can be reused as produced with the oil at the well. The chief disadvantage of the use of a wet natural gas is its commercial value for other purposes. In many cases the higher hydrocarbons may be removed for use in the production of gasoline, thereby leaving the gas dry. The dry gas often has sale value for use as fuel. Yet if the use of the gas for repressuring purposes will considerably increase the ultimate oil production from a pool, it seems

very doubtful economy to utilize it in other ways. In old fields this has often occurred, so that there is no choice left but to use other gases for repressuring.

When natural gas is not available, the gas to which a person naturally would turn would be air, which has the very great advantage of universal availability. Air is much less soluble in petroleum than is natural gas and therefore cannot lower the viscosity as much. In fact, it is very likely to increase the viscosity of many oils by reaction of the oxygen upon some of the petroleum constituents. The air will also gradually work through the formation and dilute the natural gas coming from the well, thus creating a fire or explosion hazard and multiplying the problems of corrosion of field equipment. In certain wells where the natural gas has been largely dissipated and the oil is not readily oxidized, the use of air for repressuring may be decidedly advantageous. Much better results would be expected, however, if the original gas had been kept in solution in so far as possible and if the pressure had been kept up by returning the gas to the sands as it was produced.

A combustion-gas mixture of carbon dioxide and nitrogen has the advantages over air that the oxidation, corrosion, and fire hazard effects of the oxygen are eliminated and that carbon dioxide is even more soluble in petroleum than is dry natural gas, although the nitrogen is less so. Ordinarily combustion gas would not be available in sufficient quantities for repressuring, and small amounts would only serve to dilute the natural gas produced at the well.

Hydrogen and manufactured fuel gases are not ordinarily available, and moreover are likely to be too expensive and to have too-low solubilities in the petroleum to be of much value as repressuring media. However, they would have the advantage of not seriously detracting from the fuel value of the natural gas which would be recovered in producing the oil.

In using any gas other than the natural gas from the formation, it must be remembered that the total pressure

underground is made up of the partial pressure of the natural gas plus the partial pressure of the added gas. Although the added gas may be pumped in up to the original rock pressure, still natural gas will be able to leave the solution at gas-liquid interfaces until its partial pressure corresponds to the dissolved concentration. This loss cannot take place through formation of bubbles in the body of the oil and thus can only proceed as fast as the slow diffusion process will bring dissolved gas to the interface.

A comparison of available gases points toward the great advantage of keeping as much natural gas in the formation as possible and of utilizing the gas produced with the oil for repressuring.

INFLUENCE OF COLLOIDS AND SUSPENSOIDS ON THE SOLUBILITY OF GASES IN LIQUIDS [43]

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The realization of the important rôle which natural gas plays in the production of crude oil has stimulated investigations dealing with the solubility of gas in oil. In recent years numerous large-scale experiments in repressuring oil sands in depleted fields have been undertaken and have met with varying degrees of success. Air, natural gas, and the easily condensable fraction of natural gas have all been forced back underground in key wells, and have usually led to a very definite increased production of the field.

Although air does dissolve to a certain extent in oil, it appears from the experiments in the field as well as in the laboratory that there is chemical action as well as simple solution. We shall, therefore, leave the discussion of this point to a future paper, and limit ourselves for the present to the discussion of the solubility of gases which have no

[43] American Petroleum Institute Development and Production Engineering Bull. 202, 1928, p. 101.

chemical action on oil. We shall also consider the possible influence of sand as a factor in the solubility of gas in oil, which may be of considerable importance to the oil operator interested in the efficient use of gas in oil recovery.

With the help of modern high-efficiency vacuum pumps it is possible to reduce the gas pressure in a glass vessel to practically zero in a very few minutes. If such a vessel is allowed to stand for several hours after evacuation, a small measurable pressure is reestablished. The obvious conclusion would be that the container was not gas-tight and that gas was slowly entering from outside. This is, however, easily disproved by the fact that the pressure does not continue to rise indefinitely. Moreover, by continued evacuation a pressure is ultimately established which remains at a zero value.

This behavior can be accounted for by assuming that the gas in immediate contact with the glass is held very firmly by it, with the result that the concentration, or number of molecules of gas in unit volume is greater near the surface of the container than in the body. This attraction at the surface may be due to chemical forces resulting in loose chemical compounds between the constituents of the gas and container, or it may be due merely to gravitational forces. Since the density of glass is about two thousand times the density of air, it is obvious that there should be a field of force tending to hold the gas molecules near the glass. The density of the gas being proportional to the pressure, it is concluded that a reduction of pressure would be accompanied by a release of some of the gas from the surface. This actually takes place, but at ordinary temperatures only rather slowly. Thus is explained why it is possible to reduce a pressure to zero, only to have it partly reestablished, even though the container is perfectly gas-tight.

This general property of all solids tending to condense upon their surfaces any gases or vapors with which they are in contact has been called adsorption. The term is clearly defined, and must be carefully distinguished from

such terms as absorption and occlusion. Since it has been found that under given conditions of temperature and pressure the amount of adsorption varies with the nature and physical state of the solid and with the nature of the gas, it must be concluded that adsorption is selective or specific. It has also been proved conclusively with the same solid and the same gas that the adsorption is, within certain limits, greater the higher the pressure and the lower the temperature.

Possibly the most familiar example of adsorption of gases by solids is that occurring in the gas mask. This is merely a practical application of the property discovered by Hunter in 1863, that charcoal adsorbs many gases and vapors to a marked extent. Charcoal offers a splendid illustration of the selective and specific property discussed above, since pure air may be passed through it for long periods without destroying its ability to remove toxic gases from air. The charcoal must be capable of reducing the concentration of the toxic gas from about 1,000 parts per million by volume to 1 part per million in the one-tenth of a second that the air takes to pass through it. This illustrates the remarkable selectivity which charcoal shows for some toxic gases.

In place of limiting this discussion to the interface between a gas and solid, the argument may be extended, with certain limitations, to the following: Gas-liquid, liquid-liquid, solid-liquid, and solid-solid. Since gases are miscible in all proportions, the case of a gas-gas interface does not exist.

Two things may happen at a gas-liquid interface. In the first place, the gas may concentrate at the liquid surface, or, if the liquid be a solution, say of salt in water, the salt may concentrate in the surface. Similarly, at the interface between a solid and a solution, the concentration may have a different value from the value in the body of the solution. Suppose a finely ground insoluble solid is added to a solution of known concentration. After allowing it to stand for

some time after frequently agitating the mixture to insure equilibrium, the solid is filtered off, and the concentration of the solution is redetermined. In general it will be found to be different from the initial concentration. During filtration, it is impossible to take off the last traces of solution from the solid, because of the capillary forces. Accordingly, if the concentration is higher at the interface than in the body the water held by the solid will contain more than its proportionate share of the dissolved substance. If, on the other hand, the concentration is less at the surface than in the body, the water held will have less than its share. The former action is called positive adsorption, and the solution decreases in concentration. The latter is called negative adsorption and the solution is found to increase in concentration. Both conditions have been realized experimentally.

The possible order of magnitude of adsorption phenomena may now be considered. In the case of finely divided platinum on asbestos, 400 volumes of a gas, measured under standard conditions of temperature and pressure, were adsorbed on unit volumes of platinum. In dealing with finely divided solids it is next to impossible to know the surface area to any degree of accuracy. It is known, however, that the thickness of the surface films is of the order of 2×10^{-8} inches. It is within reason to assume as a first approximation that the adsorbed gas has a density comparable with the density of a liquid. In the case of coarse suspensions, the area per unit of mass is very small, so that the mass of gas adsorbed is negligible. When, however, the solid is extremely fine, bordering on colloidal dimensions, the mass of gas adsorbed may become appreciable. If it is assumed that the particles are spherical and of about the size that would pass a 200-mesh sieve, then the volume of the layer adsorbed might be 1/200 of 1 per cent of the volume of the solid. The volume of the gas adsorbed measured under normal temperature and pressure would be about 10 per cent of the volume of the solid.

The above calculations are based on the assumption that each adsorbing particle is separate from all others. When dealing with compact oil sands, the problem assumes a somewhat different aspect.

The measure of the tendency of a liquid to become a vapor is called the vapor tension. The pressure of the vapor which has escaped from the liquid is called the vapor pressure. As the temperature is increased, the vapor tension of the liquid increases until a point is reached at which the vapor tension slightly exceeds the external pressure (usually the atmospheric pressure) on the liquid surface. At this point, the liquid passes freely into the vapor state, and is said to boil.

At a given temperature, the vapor tension, and accordingly the vapor pressure, over a flat surface of liquid is definite; the flat surface may be regarded as being part of the surface of a sphere of a radius equal to that of the earth. As the radius becomes less, the curvature becomes greater, and we come into the field of drops. It is easily shown on theoretical grounds that the vapor tension of small drops should be greater than that of large drops, and this is actually found to be true experimentally. Thus the vapor pressure of a liquid is greater if it is in tiny droplets than if it is not.

This phenomenon offers a simple explanation of the fact that rain drops during a given shower are usually about the same size. The same arguments which are used to explain a change of vapor tension with curvature of surface can be applied with equal force to the solution tension, or solubility, of coarse and fine powders. Here, also, there is an abundance of experimental proof. The solubility of gypsum has been increased by as much as 20 per cent by fine grinding.

These facts and many others lead to the conclusion that curvature of surface is an important factor in determining the properties of a substance. A little reflection will convince one that attractive forces of molecules are least satisfied at edges and corners, so that these points of greatest curvature are the most effective in adsorption. In the case

of an oil sand, the actual occurrence is a multitude of tiny cells or irregular channels between the grains. It is in these spaces that adsorption must take place. In dealing with adsorption of a difficultly condensable gas in contact with clean dry sand, it would be expected that the adsorption in these cells would be less than on the same volume of sand with the grains isolated, because in a single sand grain the curvature is convex outward, whereas in the cell, the curvature is reversed to concave outward.

If, on the other hand, sand covered with oil is being dealt with, then the relative solubility of gas in oil in bulk as contrasted with the solubility of gas in oil surfaces will have to be considered. If the sand is in a suspended condition this surface will be concave outward, whereas if the sand is compact, the surface will be convex outward.

As previously mentioned, adsorption from solution may be either positive or negative, so that it would be impossible to predict whether natural gas would be more or less soluble in pure oil than in oil in the presence of sand. Very careful experiments must be performed before anything definite can be stated. In any case it will be safe to say that an increase of solubility of as much as 5 per cent would be very large. If anything greater were encountered experimentally, it would require explanations on other grounds than those considered in this paper. In this connection it is interesting to quote from a personal letter of February 20, 1928, from B. R. Stephenson of the Marland Refining Co.:

"I wish we had some definite information to report on this subject, but so far I fear that there is only conjecture with no data to back up such opinions. I did some experiments in which I saturated a sand with gas and then with oil saturated at that same pressure and thought that I had evidence of a greater gas saturation when in the sand. After the Ponca City meeting (October 17-19, 1927), I repeated some of these runs with the gas saturation object in view. The data were inconclusive. If such an effect exists, it is much smaller than I had expected and experiments which detect this effect will have to be carefully performed to obtain conclusive evidence."

From a personal letter from R. Van A. Mills, formerly of the Bureau of Mines at Bartlesville, the following is quoted:

" There have been numerous indications that oil in sand has a greater capacity for dissolving gas than oil in a solubility chamber. Comparatively high gas-oil ratios in gas-saturated oil passing through sand-packed flow tubes have led to the opinion that the presence of sand increases the solubility of gas in oil. It is, however, extremely difficult to prove that this is actually the case unless the investigator concentrates his efforts on this particular problem. Dr. Stephenson and the engineers in our oil recovery section have agreed that this apparently higher solubility of gas in oil in sand may not, and probably does not, exist. We are all of us inclined to attribute the apparent increase in solubility to the experimental methods that we are using.

" Up to the present, only equilibrium conditions have been considered; that is to say, consideration has been given only to the effect of suspended and colloidal substances on the absolute solubility of a gas in a liquid as measured under perfect equilibrium. Comparatively little work has been done on the rate of solution and of evolution of gases in liquids, and practically nothing has been done on the question of rate of solution and of evolution of gases in liquids containing suspended or colloidal material, as compared with the rates in pure liquids.

" The fundamental laws governing concentrations in surfaces are well established. In adsorption from solution, it is known that positive adsorption takes place if surface tension decreases with increase of concentration, and negative adsorption if surface tension increases with increase of concentration. In general, it may be stated that the potential energy tends toward a minimum. Surface equilibria are very rapidly established as a result of the rather large energy changes involved. If a gas is compressed over a liquid, the surface becomes saturated very quickly. Saturation of the liquid then depends on the diffusion of the gas in solution through the body. Since diffusion takes place rather slowly, it is essential to keep the liquid agitated. If, on the other hand, the system is a solid such as porous sand saturated with a liquid such as oil, the surface entirely permeates the liquid. In this case, it is conceivable that rapid solution might take place without agitation. If, therefore, gas were compressed above two liquids of equal

volume, one pure and the other permeating a solid, it might appear that the solubility in the pure liquid was less than in the mixture, due merely to the fact that the pressure disappeared rapidly in the one and not in the other.

"When natural gas is dissolved in crude oil, the density decreases, or the Baumé gravity increases. Being lighter in weight, it tends to float on the surface, and due to the considerable viscosity of the oil, it may take a long time for it to diffuse through the entire body.

"It is very possible that the failure to recognize the existence of some of the above phenomena has led to the possible erroneous conception that natural gas is much more soluble in oil in oil sands than it is in crude oil alone. It should not be a difficult matter to settle this point experimentally.

"The general question of solubility, rate of solution, and rate of evolution of gases as affected by the presence of suspended or colloidal material is thus seen to have a very important bearing on methods of producing oil and gas. If it should be proved experimentally that natural gas dissolves very rapidly in oil in the oil sands and that it is not necessary to wait for diffusion to reach equilibrium conditions, then it could be stated that it is not necessary to conserve the gas underground. This would naturally be conditioned by the answer to the question of the availability of gas for injection or repressuring operations at some future date.

"Until it is known definitely what laws are operative, it is not safe to say that underground conditions can be explained or forecast by means of laws which are known to apply to solutions free of all solid matter."

SELECTIVE ADSORPTION

By L. D. Roberts

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If a layer of molecules is attracted to and collects on a solid surface, as air on glass, the gas is said to be adsorbed. If colored sugar syrup is filtered through charcoal the coloring is removed by being adsorbed on the charcoal. The property of adsorption is due to the residual valency at the sur-

face of the solids and also to the nature of the substance being adsorbed. Similar phenomena occur at all solid surfaces. In a crystal of common salt the valencies of the sodium and chlorine atoms within the crystals are satisfied and balanced. At the surface this is not true. Thus the surface of a solid has a valence or attraction for things,—layers of molecules,—for larger objects would not usually be brought within the range of attraction. This range of chemical attraction is perhaps about 10^{-8} centimeter.

The quantity of gas adsorbed on oil sand depends on the quality of the sand, the porosity, the nature of the oil in contact with the sand, the temperature, and the pressure. A given surface will adsorb from a mixture of gases different amounts of the various constituents.

The air adsorbed on the surface of a glass capillary tube causes the surface of water rising in it to be concave. Mercury does not seem to wet the glass. However, if the air film is completely removed from the glass, mercury wets the glass as water does. This is at least true for some kinds of glass. Water displaces the adsorbed air while mercury does not. Water is adsorbed most strongly, air next, and mercury least. The study of oil removal and gas pressure may involve a study of selective adsorption.

Various solid surfaces adsorb gases and liquids in quite different amounts. The same surface will adsorb very different quantities of various gases and liquids. Gas introduced for repressuring will modify the adsorption.

The empiric equation of Freundlich,[44] $\frac{x}{m} = ap^{1/n}$, where x is the weight of the gas adsorbed, m the mass of the solid, p the pressure of the gas, a is a constant depending on the units, and n depends on the nature of both the gas and the solid, shows very well the relation of the amount of gas adsorbed and the pressure.

[44] Freundlich, Herbert, Colloid and Capillary Chemistry, translated from the third German edition by H. Stafford Hatfield: London, Methuen & Co., Ltd., 1926, p. 110.

Solids adsorb ions from a solution. The surface of the solid will become electrically charged, the nature of the charge depending on the ions adsorbed. Bains [45] and the writer, at the Colorado School of Mines, have determined the charges on several mineral surfaces in various solutions. This work has been done in reference to flotation. Ions are selectively adsorbed.

Sometimes it is difficult to distinguish between the two phenomena, adsorption and absorption. McBain [46] has suggested the term " sorption " to include the two phenomena.

Surface energy is caused by the unsaturated condition. Corners and rough places will exhibit a larger degree of adsorption.

FILMS AND INTERFACES

In the body or interior of a liquid the forces acting on a molecule are the same in all directions, but at the surface there are no other molecules of the same kind above those in the surface layer. At the surface of a liquid in contact with air the upper layer acts as a skin stretched over a liquid. If any two phases are in contact, a thin layer of matter separates the two homogeneous phases; this thin layer differs in properties from those of the two phases. At boundaries or interfaces between phases there are films.

The phase at the interface of two liquids is complicated by the fact that there is mutual solubility of the two liquids. In oil fields, water and oil form interfaces both in ordinary layers and in emulsions. Oils of different densities and hydrocarbon gases modify the phases at these interfaces.

Interfacial tension between two liquids is equal to the difference between two surface tensions. Interfacial tension, like surface tension, diminishes with increase of temperature. Dissolved substances may concentrate in a film, and also colloidal particles may concentrate in a film. Thus

[45] Thomas M. Bains, jr., Associate Professor Mining, Colorado School of Mines, Golden, Colo.

[46] Rideal, Eric Keightley, Introduction to Surface Chemistry: The Cambridge (Eng.) University Press, 1926, p. 123.

at interfaces and films, physical and chemical changes may be intensified.

The formation of films of liquid upon a solid surface or on another liquid is very important. Four criteria for spreading have been suggested, but since they are not all in agreement they cannot all be correct. The one given by Harkins[47] is widely accepted. If the work of surface cohesion, W_c, is less than its work of adhesion, W_a, with respect to the surface of the other substance, the liquid will spread. Water does not readily penetrate sand already wet by oil.

VOLUMETRIC FACTORS OF REPRESSURING

Geological Conclusions

Data on repressuring operations in certain Texas fields indicate but do not show definitely that it is impossible to return to depleted or partly depleted sands a volume of gas equal to that previously removed. Four geologic factors are believed to be responsible, at least in part, for the apparent difference between the volume of gas taken out of the formations and the volume of extraneous gas which ordinary repressuring operations return to the sands. These factors, arranged in the order of their importance are (1) time, (2) water encroachment, (3) slumping, and (4) recementation.

Although the time factor is of paramount importance in repressuring operations, petroleum engineers have been disposed to treat it too lightly. It must be remembered that during the early life of a field, gas is withdrawn from the reservoir sands through a relatively large number of wells, whereas during repressuring the ratio of injection wells to producing wells is from one to five, or greater. In order, then, to repressure a field where there is but one injection well to every five or more producing wells it would be necessary to return gas to the reservoir formation at a rate at least five times greater than that at which the gas was

[47] Bogue, Robert Herman, Theory and Application of Colloidal Behavior: McGraw Hill book company inc., N. Y., 1924, vol. 1, p. 170.

originally produced from the average well. Since the flow of gas through a restriction or opening between two reservoirs—one of which is the well and the other the pore spaces in the reservoir sands—varies as the square root of the differential pressure and as the absolute static pressure, it is evident that there is a maximum rate for a given injection pressure and number of intake wells at which a field can be repressured.

The volume of gas which a depleted or partly depleted sand is capable of taking during a given period is dependent also upon the character of the reservoir formation. Every formation contains streaks of more or less loose and tight sand. The loose streaks fill with gas rapidly, but it takes time to fill the voids in the tighter portions of the sand. If injection pressures are maintained for a sufficient length of time, it should be possible, provided of course that the pressures are as high or higher than the original formation pressure and other shrinkage factors do not interfere, to return the original volume of gas to the reservoir sands. The distribution of energy and pressure in a depleted sand is a slow process at best. It can be hastened to some extent by increasing the injection pressure or by using a larger number of injection wells; but in any event a long time, and in the average reservoir sand perhaps years, will elapse before original conditions can be restored.

That 100 per cent return of gas to the reservoir, even where sufficient time has been allowed, is not always possible in depleted oil sands is sometimes due to water encroachment. Water which has migrated into the depleted areas of a sand reduces appreciably the volume of pore space available for injected gas.

Slumping of the sand formation is held by some engineers to be a factor in reducing the pore spaces in reservoir sands and is considered by them to be one of the reasons why certain formations did not take as much gas as they held originally. In a producing formation having a high initial pressure and no edge water it is probable that subsidence

may contribute to pore space shrinkage on depletion of the oil and gas from the formation. High-pressure fields without edge water, however, are of rare occurrence. In those fields which are surrounded by edge water, as, for example, the Gulf Coast fields in Texas and the majority of fields in California, slumping of sand formations after the extraction of oil and gas seems but a remote possibility. In considering reservoir sands which are surrounded by edge water, many engineers are of the opinion that if the pressure of the overlying formations was great enough to compress the depleted sand bed the pressure would be more than enough to supply the required differential between the water and the depleted sand to cause the water to replace the extracted gas and oil before compression of the sand took place.

Although recementation in the reservoir sands has been offered as a possible factor in pore space shrinkage, no substantiating data for or against this theory are available at this time.

THE JAMIN EFFECT

By H. A. Wilson

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The "Jamin effect" is an increase in the forces required to produce a given flow of a liquid through narrow spaces due to the presence of bubbles in the liquid. The effect may be studied with a long glass tube of about ¼ millimeter inside diameter. If such a tube contains water or oil separated into small sections by air bubbles, then it is found that the rate of flow due to a given pressure is much less than when the tube is completely filled with the liquid. The effect is due to surface tension. When a narrow tube is partly filled with a liquid which wets the tube, as in the case of water or oil in a glass tube, the surface of the liquid is concave; but when the liquid is at rest, it is approximately a hemisphere having a radius equal to the radius of the tube. Due to sur-

face tension, the hemispherical surface exerts a pressure equal to $\frac{2T}{R}$, where T denotes the surface tension and R the radius. Thus the pressure in a short length of liquid at rest in a tube of radius R is less than the pressure in the gas just outside the liquid by $\frac{2T}{R}$. If now the pressure in the gas at one end of the short length of liquid is made greater than that at the other end, the liquid will move along the tube. The motion of the liquid causes the surface of its front end to be flattened and that of its back end to become more concave. The pressure difference due to surface tension at the back end of the length of liquid thus becomes greater than $\frac{2T}{R}$, and that at the front end less than $\frac{2T}{R}$, so that there is a resultant force due to surface tension tending to retard the motion along the tube.

In Figure 36, AB represents a short length of liquid at rest in a narrow tube, and CD the same liquid when moving

FIGURE 36.—Shape of surfaces of short lengths of liquids at rest and when moving from left to right in a narrow tube

from left to right. The change of the shape of the surfaces due to motion is caused by the viscosity of the liquid which retards the motion into and out of the narrow parts of the space between the liquid surface and the wall of the tube. The retarding pressure may be supposed to be of the order of magnitude of $\frac{2T}{R}$. Thus, with a liquid of surface tension of 50 dynes per centimeter in a tube of radius 0.1 millimeter,

the retarding pressure would be of the order of 10,000 dynes per square centimeter. A series of 1,000 short lengths of the liquid with gas in between might therefore exert a retarding pressure of about 10,000,000 dynes per square centimeter or of 150 pounds per square inch.

If, instead of a uniform tube, a mass of sand with oil and minute bubbles in the narrow spaces between the grains is considered, it is easy to see that there will be a similar retarding pressure due to the presence of the bubbles when the oil and bubbles are moving through the sand. But in the case of oil and bubbles in sand there may be a retarding pressure even when the oil is not actually flowing; that is, there may be almost no flow unless the driving pressure is greater than a certain definite value. This is possible because when the oil is at rest the bubbles tend to take shapes as nearly spherical as possible. The bubbles therefore tend to get into the wider parts of the spaces between the sand grains, leaving the oil in the narrower parts. To start the oil and bubbles flowing, it is therefore necessary to apply sufficient pressure to force the bubbles from the wider spaces into the narrower spaces.

The pressures due to the Jamin effect in oil sand may be very large because of the fine grain of the sand. If the grains are about 0.01 inch in diameter there may be 1,200 bubbles to the foot so that the pressure required to start the oil flowing may be as much as 100 pounds per square inch per foot of sand thickness.

Jamin[48] showed that a narrow tube having a series of very small enlargements or bulbs on it containing a liquid, with an air bubble in each bulb, could support a pressure of several atmospheres without appreciable flow.

The existence of a retarding pressure due to surface tension in sand containing oil and bubbles may also be deduced as follows: When the oil is at rest the bubbles must be so arranged that the energy of surface tension has a minimum

[48] Jamin, Comptes rendus des séances de l'Academie des Sciences, t. 50, 1860, pp. 172, 311, and 385.

value. Any displacement of the oil and bubbles must therefore increase the energy of surface tension, so that there must be a force due to surface tension tending to oppose any such displacement.

It is clear that the Jamin effect in oil sand depends on the number of bubbles present. If only a few are present they will block the pores in which they are and leave the oil free to flow in the other pores. The greatest Jamin effect will occur when there is about one bubble to each sand grain. A few large bubbles will not have much effect.

IMPORTANCE OF RETAINING GAS PRESSURE IN PETROLEUM DEPOSITS

By Wm. L. Lacy

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Petroleum deposits in general are accompanied by natural gas. The gas is of similar origin to that of the rest of the petroleum and is composed of hydrocarbons of low molecular weight. These volatile hydrocarbons may be condensed to liquid state by a sufficient increase of pressure or lowering of temperature, or by both together. In a similar manner the liquid hydrocarbons may be converted to the gaseous state by decrease of pressure or increase of temperature. The dividing line, then, between natural gas and liquid petroleum is one which shifts with change of pressure or temperature.

In view of this similarity it is not surprising that natural gas, even under temperatures and pressures at which its constituents are gases, is soluble to a certain extent in the liquid hydrocarbons. When oil and gas are found under pressure, coexistent in a formation, the oil is saturated with dissolved gas. The higher the pressure, the more gas will be condensed to liquid or dissolved in the liquid hydrocarbons. If the pressure upon the system is decreased, the gas solubility is decreased, and some material which was

contained in the liquid phase becomes gaseous. This formation of gas will occur throughout the liquid wherever the pressure is lowered.

When gases and volatile hydrocarbons are removed from the solution, the physical properties of the latter are changed. The resulting liquid has greater density, greater viscosity, and greater surface tension than when the light hydrocarbons were present in larger proportion. The extent of these changes will depend, of course, upon the amounts removed from solution, which in turn depend upon the decrease of pressure.

In the formation below the surface of the earth, the petroleum is found dispersed throughout the small interstices of porous " oil sands " saturated with gas under pressure which may be as high as 100 atmospheres or even higher. When a well is drilled into this formation and fluid is allowed to flow out, the pressure at the intake of the well is decreased. This immediately causes a pressure gradient in the formation which tends to force fluids toward the well intake where the pressure is lower.

Consider what will happen as this process is continued. The pressure throughout the formation gradually decreases. The possible pressure gradient from the remote parts of the formation toward the well is decreased, and therefore the available energy for driving the fluids to the well is lowered. The lowered pressure allows dissolved gas to separate from the liquid petroleum in proportion to the decrease of pressure, and the gas forms minute bubbles in the oil. These bubbles grow in size and often join to form larger ones. The oil, to reach the well, must flow through fine capillary pores between the sand grains. The presence of these gas bubbles, which offer considerable resistance to the distortion necessary to force them through the capillaries, offers a serious impediment to the desired flow of oil.

Another disadvantage of the release of dissolved gas lies in the resulting increase in viscosity of the oil. Increased viscosity has the effect of adding greatly to the difficulty

of flow toward the well, requiring a greater pressure gradient for a given flow rate and thus absorbing more of the available energy than is desirable.

Still another troublesome result of gas coming out of solution from the oil is the increase in surface tension of the liquid and the greater tendency to hold tight to the capillary sand pores. This condition involves the expenditure of more energy to remove the oil from the sand and increases the proportion of the oil which cannot be economically recovered. This unrecovered fraction is large at best.

As is easily seen, the release of dissolved gas in the formation is unfortunate and should be avoided as much as is feasible. Some decrease in pressure in the formation is necessary to cause oil to flow to the well inlet. There are two ways of getting a given flow rate to the well: First, use a low pressure gradient, thus holding gas in solution and taking advantage of lower viscosity and adhesion and the presence of fewer and smaller gas bubbles to counterbalance the lower energy availability; second, let the pressure at the well inlet drop low, allowing greater quantities of gas to escape and opposing much greater resistance to flow, but relying upon the greater pressure gradient to supply the additional energy required. It is not difficult to decide which of these two procedures will give the largest ultimate yield of oil with the least expenditure of energy from the formation. Unfortunately, the second method has been very commonly used.

Even though the pressure is kept reasonably high at the well inlet, the formation pressure will gradually drop, if no other steps are taken, because of the removal of gas and oil. To avoid this difficulty, gas may be forced into the formation, keeping the pressure up, replacing the energy used, and keeping the dissolved gas in solution; this should be begun as soon as possible after production is started. It might seem practicable, at first sight, to use the rock pressure as long as it lasted and then pump gas into the forma-

tion to furnish energy to move the oil. This is not, however, the most advantageous procedure, because, during the first stage, the residual oil is largely depleted of its dissolved gas and is therefore more viscous and harder to remove from the sand. Although the gas pumped in under high pressure will tend to redissolve in the residual oil, the process is likely to be very slow. This is because the gas can only dissolve at exposed surfaces of oil and must travel into the body of the liquid by diffusion, a particularly slow process in the viscous oil. If the sand were nearly depleted, as judged by past production methods, there would be more exposed surface for solution of gas; but there would also be much greater chance that open passages through the sand would allow the gas to by-pass the oil and reach the well inlet without bringing oil with it.

In many cases the maintenance of original rock pressures should have another advantage in keeping back the water bodies at the edges of and below the oil-bearing sands. In some fields this encroachment may be advantageously allowed, the hydrostatic pressure causing the water to drive the oil through the sand to the well. However, in other fields the water, instead of making a complete replacement, is likely to pass more rapidly through some parts of the formation than others and will tend to surround bodies of oil-bearing sands. The oil thus isolated is very difficult of recovery, and its economic production is very unlikely. By keeping the pressure in the oil sufficiently high this uneven water encroachment should be lessened and often completely avoided. This would be accomplished not only by holding the water back, but, owing to decreased surface tension and viscosity, the oil would have a greater tendency to flow and to remain consolidated.

Although the main physical principles involved in the more efficient recovery of petroleum may be stated briefly, the task of actual operation in the field is complicated in many ways and requires all the technical skill of the petro-

leum engineer. Economic factors and idiosyncrasies of the individual field (often very difficult to ascertain early in the life of the field) serve to make the engineer's task a difficult one, and he deserves the very great assistance of the whole-hearted coöperation of operators, owners, and lease holders in allowing the oil pools to be developed by methods that will insure the greatest ultimate recovery.

RESERVOIR AND FLUID TEMPERATURES

A knowledge of subsurface temperature is essential to the study of gas-energy relations in oil sands and the efficiency of production methods. Unless the temperature as well as the pressure and physical properties of the oil in reservoir sands is known, the volume of gas dissolved in the oil cannot be determined from data obtained at the well head. Neither is it possible to calculate the viscosity of oil at the bottom of wells or in reservoir sands from data obtained at the casing head. Moreover, flowing efficiencies depend upon the extent to which the energy contained in the formation gas is utilized in lifting oil and the manner in which the gas expands as it rises in the flow tube. Therefore the relative efficiency of flow in a well cannot be determined unless the temperature of the fluid and the pressure at the inlet, as well as at the surface end of the flow tube, is known.

It has been assumed, generally, that subsurface temperature increases approximately 1° F. for every 50 feet of depth, but temperature measurements taken in deep oil wells show that the temperature gradient varies in different wells and in different fields. For example, in certain wells in Pennsylvania the temperature gradient indicated a rise of 1° F. for each 58 to 64 feet of depth, and in the California oil fields a rise of 1° F. in 52 feet is of frequent occurrence. Other temperature measurements indicate that in some localities the temperature rises at even a faster rate, frequently 1° F. for every 40 feet.

TEMPERATURE OBSERVATIONS IN WELLS

In the Salt Creek field, Wyo., well temperatures at a depth of 100 feet varied from 51.4 to 65.27° F. and from 79 to 98.4° F. at a depth of 2,000 feet. Temperature measurements in a well in the Teapot Dome field, Wyo., show a temperature of 71.6° F. at a depth of 1,000 feet and 125° F. at 2,867 feet. In another well in the same field the temperature at a depth of 25 feet was 76° F., and 124.5° F. at a depth of 2,790 feet. A completely dry well in the Teapot Dome field showed a temperature of 52° F. at 100 feet and 101° F. at a depth of 2,000 feet. In a number of wells in California the temperature at a depth of 4,000 feet varied from 150 to 170° F. A thermometer run to the bottom of a 4,500-foot well in the Wellington-Fort Collins district, Colo., registered 157° F., three degrees higher than that found at the bottom of a 7,900-foot well near Kane, Pa.

Temperature measurements made by Hawtoff,[49] of the Bureau of Economic Geology, in a well in the Big Lake field, Reagan County, Tex., show the following temperatures at depths below 5,000 feet:

Depth in feet	Temperature, °F.
5,700	122
6,500	135
7,000	152
8,000	161
8,300	170

Data on temperatures in three deep wells at Ligonier, Pa., obtained by Van Orstrand,[50] of the U. S. Geological Survey, are given in Table 21.

Observations of temperature at the bottom of deep wells in various parts of the United States, as recorded by Van Orstrand[51] in his paper "Temperatures in World's Deepest Wells," are given in Table 22.

[49] Hawtoff, E. M., Temperature Data of Deep Well Interesting: Oil and Gas Journal, November 1, 1928, p. 38.

[50] Van Orstrand, C. E., Temperature in World's Deepest Wells: Oil and Gas Journal, April 19, 1928, p. 39.

[51] Van Orstrand, C. E., U. S. Geological Survey. Paper published in Oil and Gas Journal, April 19, 1928, p. 39.

TABLE 21.—TEMPERATURE OBSERVATIONS IN THREE DEEP WELLS AT LIGONIER, PA.

Depth, feet	Temperature, °F.		
	Well No. 1,842	Well No. 1,586	Well No. 1,699
100	50.7	49.9	50.7
500	55.8	55.9	56.1
1,000	63.0	63.1	63.2
1,500	70.6	71.0	71.1
2,000	78.6	77.9	79.2
2,500	85.9	86.1	86.1
3,000	93.0	93.3	91.5
3,500	100.8	100.9	98.4
4,000	107.8	108.1	106.1
4,500	117.2	116.4	115.2
5,000	127.4	126.6	123.2
5,500	137.8	137.8	132.1
6,000	148.7	148.8	141.5
6,500	158.2	.....	151.2
6,750	166.1	.....	154.7

TABLE 22.—TEMPERATURE AT BOTTOM OF DEEP WELLS IN VARIOUS FIELDS OF THE UNITED STATES

Well location	Depth, feet	Observed temperature, °F.
Goff, Clarksburg, W. Va	7,310	159.3
Lake, Fairmont, W. Va	7,500	168.6
No. 1,842, Ligonier, Pa	6,500	158.2
Day, Gaines Junction, Pa	5,500	134.8
Hughes No. 1, Lost Soldier, Wyo	1,925	144.2
Johnson No. 1, Longmont, Cal	6,500	210.3
Bastanchury No. 5, Fullerton, Cal	4,270	154.5
Henderson No. 1, Ozona, Tex	5,500	151.4
Boston Barnet No. 1, Holdenville, Okla	5,200	166.0
Olinda No. 96, Brea, Cal	8,046	223.0 *

* Reported by the Chanslor-Canfield Midway Oil Co.

TEMPERATURE CHANGES BROUGHT ABOUT BY RELEASE OF PRESSURE

The temperature of oil decreases as it flows from the reservoir sands to the surface. The drop in temperature is caused partly by the expansion of the gas which accompanies the oil and partly by the cooling effect of the upper formations. The most important influence however is that of the expansion of the gas. Sclater and Stephenson[52] found the temperature of the oil and gas in a flowing well in Texas to be 42° F. lower at the casing head than at the bottom of the well. The depth of the well was 3,389 feet. This well was flowing at the rate of 300 barrels of oil and 374,000 cubic feet of gas a day through 5 3/16-inch casing. At the bottom of the hole where the pressure was 325 pounds per square inch, the temperature of the oil and gas mixture was 124° F., whereas at the casing head, where a pressure of 50 pounds per square inch was maintained, the temperature was 82° F. In another Texas well in which production was pinched back to 50 barrels of oil and 27,500 cubic feet of gas a day flowing through $6\frac{5}{8}$-inch casing, the temperature of the oil and gas at a depth of 2,899 feet (bottom of the well) was 127° F. The well pressure at this point was 310 pounds per square inch. At the casing head where the pressure varied between 10 and 25 pounds per square inch, the temperature of the oil and gas mixture was 86° F. or 41° less than at the bottom of the well.

Production tests on wells in the Salt Creek field, Wyo., showed a relation between fluid temperature at the well head and gas-oil ratios. The tests indicated that temperatures at the casing head are higher usually when gas-oil ratios are low than when large excesses of gas are produced with the oil. When the volume of gas accompanying the oil to the

[52] Sclater, K. C., and Stephenson, B. R., Apparatus for Measuring Conditions at Bottom of the Hole: Presented before Petroleum Division, A. I. M. & M. E., Tulsa, Okla., Oct. 18-19, 1928; published in National Petroleum News, Oct. 31, 1928, p. 59; and in Oil and Gas Journal, Oct. 25, 1928, p. 114.

surface is greatly in excess of that required for efficient flow, large volumes of gas expand in the flow tube without doing a corresponding amount of useful work. This expansion causes increased cooling of the rising mixture and results in a lower temperature at the well head than if gas-oil ratios had been lower.

This relation between temperature and gas-oil ratios was observed also in the Wellington-Fort Collins district, where invariably the lowest fluid temperatures (measured at the well head) were on high gas-oil ratio wells. Incidentally, also, the highest well-head temperature in this district was on a well making 60 per cent water.

Hill and Sutton [53] in discussing fluid temperatures at wells in the Powell field, Navarro County, Tex., report that

"Wells producing clean oil were found to have a temperature of 80 to 95° F. at the casing head, whereas wells producing water ran from 105 to 120° F., depending upon the quantity of water produced. It was observed that an increase in water was ordinarily followed by a rise in temperature of the fluid. The warmest fluid tested registered 120° F. and was obtained at a well producing 25 barrels of oil and 575 barrels of water."

No measurable differences in temperature have been noted in certain productive sands as a result of gas expansion, while appreciable differences have been found in others. For example, a correlation of temperatures shows that there has been no measurable drop in temperature in five years in the productive sands in the Salt Creek field, Wyo., as a result of the expansion of gas. On the other hand, data have been published [54] proving that temperatures in the

[53] Hill, H. B., and Sutton, Chase E., Production and Development Problems in the Powell Oil Field, Navarro County, Tex.: Bureau of Mines, Bull. 284, p. 54, 1928.

[54] Pennington, Harry, Duty of Formation Gas: The Oil Weekly, August 24, 1928, p. 48.

Northwest Extension field, Wichita County, Tex., have decreased 22° F. in 3½ years and 33° F. in 8 years.

CRITICAL TEMPERATURES OF HYDROCARBON GASES

For each gas there is a temperature above which it cannot be liquefied, no matter how much pressure is used. This temperature is known as the critical temperature for that gas. Any gas or vapor may be liquefied at any temperature below its critical temperature if subjected to sufficient pressure. The critical temperatures of constituent gases found in natural gas are given in Table 16, page 196.

ORIGINAL CAUSES OF FORMATION PRESSURE

VAPOR PRESSURE

The pressure exerted by the vapor from a liquid, when the vapors and liquid are in equilibrium, is called the vapor pressure of the liquid. The pressure exerted against the interior of a vessel by a given quantity of a perfect gas inclosed in it is the sum of the pressures which any number of parts into which such quantity might be divided would exert separately if each were enclosed in a vessel of the same volume at the same temperature.

In an undisturbed formation, the structure pressure is made up of the partial pressures of the gaseous and liquid components. Little is known of the changes which take place after drilling into reservoir formations because the complexity of the components and phases make it difficult to translate surface data back to underground conditions.

HYDROSTATIC PRESSURE

The close agreement in many cases between the observed pressures at any depth of bore and the hydrostatic head from that level to the surface water table suggests that a hydrostatic equilibrium has been reached even though no con-

necting channels of water exist. This opinion is based on data assembled by Shaw,[55] Table 23. The last column in this

TABLE 23.—DEPTH OF OIL SAND, INITIAL GAS PRESSURE, AND PRESSURE PER HUNDRED FEET OF DEPTH BELOW SURFACE FOR VARIOUS OIL FIELDS OF THE UNITED STATES

Field	Depth of oil sand, feet	Initial pressure, lbs. per sq. in.	Recorded pressure per hundred feet of depth below surface, lbs. per sq. in.
Burbank, Okla.	2,950	800	27.1
Caddo, La.	3,623	1,200	33.1
Caddo, La.	1,650	650	39.3
Cotton Valley, La.	2,556	900	35.2
Cushing, Okla.	2,092	725	34.6
Dominguez, Calif.	4,200	1,470	35.0
Dominguez, Calif.	4,223	820	19.4
Mirando City, Tex.	1,944	635	32.6
Rosecrans, Calif.	4,125	1,444	35.0
Rosecrans, Calif.	4,125	800	19.3
Smackover, Ark.	2,200	900	40.9
Wellington, Colo.	4,285	1,400	32.6
Westmoreland, Pa.	6,822	3,600 *	52.7
Lost Soldier, Wyo.	2,700	1,000	37.0
			33.8 (average)

* Estimated by the operators

table was added by the editor to show the relation that exists between depth and pressure.

CHEMICAL REACTIONS

During the formation of oil in closed spaces, chemical reactions which evolved gas, or tended toward volumetric increase, would result in an increase in pressure. It is generally agreed that decomposition of certain organic matter produced petroleum originally. Decomposition of matter is a chemical reaction, and if carried on in the laboratory in a closed container—that is, at constant volume—pressure would be built up because of the chemical reaction. The

[55] Shaw, S. F., Energy Contained in Petroleum Gas: Mining and Metallurgy, January, 1926, p. 10.

amount of gas obtained would be controlled by the pressure developed by the reaction, and this pressure would be limited to the given amounts of the various constituents. It is reasonable to assume that chemical reactions of a similar nature occurred underground and, in the opinion of certain scientists, formation pressure is an equilibrium pressure such as is spoken of in chemical reactions.

GEOLOGICAL FOLDING

Increases in formation pressure may have been caused by folding, or compaction, which decreased the volume of the oil or gas reservoirs. Matier,[65] in discussing the possible reason for a well in the Purisima Hills, Santa Barbara County, Calif., flowing continuously for 20 years and then flowing again after a two years' shutdown, advances the theory that "the Purisima Hills have been created by a large anticlinal movement, and this is expressed at the particular point where this well is located by a well-identified overturn, and that the underground reflection of it may manifest itself in tectonic pressure being put on the oil sand. The absence of gas may go to strengthen this theory, for in the entire field, where the Union Oil Co. has some thirty-odd wells spaced far apart, there is only sufficient gas for operating requirements."

EARTH'S TEMPERATURE

The conduction of heat from the earth's interior is believed to be an original cause of pressure in underground formations, but substantiating data are lacking.

DECLINE IN GRAVITY OF CRUDE OILS WITH AGE OF FIELD

As formation pressures decline, the gravity of the oil from the reservoir sands decreases. The decline in gravity,

[65] Matier, Hugh A., Well Doubles Production after Flowing Twenty-Three Years: The Oil Age, August, 1928, p. 49.

however, may be retarded and the gravity maintained by the application of back pressure on wells. It has been the experience in California, where, as a rule, trap pressure is held on new wells, that oil produced under high pressure is from 1 to 2° A. P. I. gravity higher than when little or no trap pressure is held on the wells. Changes in gravity are usually less pronounced and of small magnitude after wells enter the pumping stage. However, when vacuum is applied to pumping wells the gravity of the oil produced decreases usually in direct proportion to the amount of vacuum held on the wells. The gravity of crude oils is affected also by the gas lift. When " dry " gas is circulated in a gas-lift well, oil gravities are decreased slightly; on the other hand, a small increase in gravity is noted when " wet " gas is circulated.

Data have been collected in the Cook pool, Shackleford County, Tex., which show that there is a relation between gas-oil ratios and gravities of oil produced and that high gas-oil ratios are conducive to the production of oil of sub-normal gravity. For example, certain leases were producing oil of 35.5° A. P. I. gravity with a gas-oil ratio of 14,000 cubic feet per barrel, whereas the normal gravity of the oil produced in this field in wells where gas-oil ratios varied between 285 and 627 cubic feet per barrel is 39° A. P. I. It is apparent, therefore, since oil is sold generally on the gravity basis with the higher gravity oil commanding the better price, that every effort should be made to maintain the gravity of the oil as high as possible. This can be accomplished by (1) strict control of gas-oil ratios, (2) production methods that bring the oil to the surface with the minimum amount of gas, (3) maintaining trap pressure on new wells, and (4) storage facilities that prevent evaporation of the lighter constituents of crude oils.

Initial gravities of crude oils produced from a number of wells in various fields, and gravities one or more years later, are given in Table 24. The table shows that over a

TABLE 24.—INITIAL AND SUBSEQUENT GRAVITIES OF CRUDE OILS FROM WELLS IN VARIOUS FIELDS OF THE UNITED STATES AT YEARLY INTERVALS

Location of well	Gravity, °A. P. I., initial and after number of years shown in column heading										
	Initial	1	2	3	4	5	6	7	8	9	10
Ranger, Tex.	39.7	....	35.5	....	....	36.8–39.3	....	....	....	....	....
Ranger, Tex.	36.1	....	....	39+	....	....	....	....	39.2	....	....
Ranger, Tex.	39.3	....	....	37–38.9	....	....	....	....	38.5	....	....
Crosscut, Tex.	42–42.9	37.5	....	....	....	....	....	....	....	....	....
Crosscut, Tex.	43–43.9	41.6	....	....	....	....	....	....	....	....	....
Powell, Tex.	37–37.2	....	....	36–36.9	35.1	....	....	....	....	....	....
Powell, Tex.	36.6–38.0	....	....	35.9–37.9	35.9	....	....	....	....	....	....
Breckenridge, Tex.	40.4	33–35.9	....	....	....	....	35.2–35.8	....	....	....	....
Breckenridge, Tex.	38.6–39.0	....	38.9–39.9	....	....	....	....	36.7–37.7	....	....	....
Mexia, Tex.	36.1–36.4	....	....	....	....	36–36.9	36.3–36.7	....	....	....	....
Mexia, Tex.	36.1–36.4	....	....	....	....	35–35.9	34.2–36.8	....	....	....	....
Burkburnett, Tex.	42.0	....	....	....	....	....	39+	....	....	....	40.2
Burkburnett, Tex.	41.0	....	....	....	....	....	39+	....	....	....	37.6
Richfield, Calif.	27.0	26.0	25.0	24.2	24.8	23.3	....	....	....	....	....
Richfield, Calif.	28.9	27.0	26.5	25.8	24.6	24.5	23.7	....	....	....	....
Santa Fe Springs, Calif.	33.8	32.8	33.9	33.5	....	....	....	....	....	....	....
Santa Fe Springs, Calif.	28.6	28.8	28.3	....	....	....	....	....	....	....	....
Santa Fe Springs, Calif.	31.5	31.0	31.1	31.4	....	....	....	....	....	....	....
Purisima Hills, Calif.	20.0	....	....	....	....	....	....	....	....	....	20.8*
Huntington Beach, Calif.	26.0	26.0	26.0	25.7	25.5	25.4	....	....	....	....	....
Long Beach, Calif.	28.6	27.8	27.7	26.6	....	....	....	....	....	....	....
Salt Creek, Wyo.	40.8	....	....	....	....	....	....	35.0	34.8	....	....
Salt Creek, Wyo.	38.5	....	....	....	....	....	....	36.7	37.9	....	....

* 23 years after bringing in.

long period, subsequent gravities are generally less than initial gravities. Only 4 wells out of the 23 listed show higher gravities at the end of 6 or more years.

SUMMARY

The following summary is based on the more important data presented in the text and also as far as possible on the expressions of opinion contained in the reports of the four regional technical committees of the American Petroleum Institute's committee on gas conservation.

The order of arrangement follows, in a general way, that of the preliminary summary made by the four regional chairmen (see introduction), and divides the subject matter into three main parts, answering the three questions propounded.

I. THE IMPORTANCE OF NATURAL GAS IN THE PRODUCTION OF PETROLEUM

The conservation of natural gas in the production of oil is of paramount importance. For example, it is estimated that in 1927 in one field alone—the Burbank in Oklahoma—gas conservation would have resulted in the production of at least 20,000,000 additional barrels of oil. Had pressure control been applied to this field as a unit, approximately $36,000,000 of additional revenue would have been realized in one year from oil that will remain unproduced because of uncontrolled production methods. Also, many wells would have flowed naturally for a longer time under pressure control, and lifting costs would have been reduced materially. The cost of lifting oil by natural flow is much less than by other means and therefore a greater profit per barrel of oil would have been realized. Although the gas in excess of the estimated amount required to produce efficiently Burbank field's 1927 production had a potential value of approximately $2,000,000 at the casing head, it would have had a greater value as expulsive energy if

utilized to its fullest extent in moving oil though the reservoir sands to the wells.

Pressure control of wells is a major factor in the production of oil. A better realization of what can be accomplished to conserve gas and increase the recovery of oil from the sands has come to the petroleum industry within recent years. Savings of oil and gas and increased earnings which already have been effected in fields where pressure control has been applied are indicative of the results which may be accomplished by the petroleum industry if every operator will study his problems in the light of pressure control.

FUNCTION OF GAS IN THE RESERVOIR

(a) Gas associated with or in contact with the oil in reservoir rocks provides the propulsive energy which moves oil to the wells. All petroleum engineers are agreed that where gas provides this energy the exhaustion of oil from oil-bearing formations is due more to depletion of the gas than to actual exhaustion of oil. Water and gravity also play a part in oil recovery, but gas usually provides the main force which moves oil through the reservoir rocks to the wells. Because of the influence of gas in the production of oil, and by reason of its importance, the common supply should be controlled in the common interest.

(b) The amount of gas associated with a barrel of oil depends largely upon pressure. Gas is commonly believed to exist in four phases in the reservoir:

(1) As free gas in higher portions of the structure.
(2) As a liquid where pressure is sufficiently high.
(3) In solution in the heavier liquid hydrocarbons present.
(4) Adsorbed at the interfacial surfaces.

(c) Natural gas in solution lowers the viscosity and surface tension of the oil in the reservoir, thereby reducing the resistance to movement of oil in the sand toward the well. The volume of gas held in solution in oil is in direct proportion to the pressure, if other conditions remain constant.

Holding as much of the gas in solution in the oil as possible will therefore keep the oil more fluid, and through lowered surface tension and the lessened growth of bubbles will thereby reduce that resistance to flow which is known as the Jamin effect.

(d) Temperature measurements, where available, indicate that the production of oil and gas sometimes reduces the original formation temperature. Such temperature changes as do occur probably are localized to the immediate vicinity of the well, possibly almost wholly within the well.

(e) Gas injection compensates to a degree for some of the harmful effects of producing oil with high gas-oil ratios, but it cannot reproduce original conditions in the reservoir. The factors considered of greatest importance are:

1. Time.
2. Lack of agitation.
3. Slow rate of diffusion.
4. Inability to replace adsorbed gas.
5. Change in character of gas returned due to extraction of gasoline.
6. Relative small number of injection wells as compared to producing wells.
7. Water encroachment.
8. Differential permeability (the inability to direct the gas to the particular sand desired).

(f) *Repressuring with gases other than the original gas.* The use of air is considered undesirable where the oil is asphaltic, or contains many unsaturated compounds which are readily oxidizable. Air is less soluble and does not reduce the viscosity or surface tension as does natural gas. Corrosion of casing and tubing, particularly if the oil be high in sulfur, is almost sure to result from the use of air as a substitute for gas. Also, compressed air vitiates the gas still remaining in the reservoir rocks, and as the supply of gas for fuel is usually low in districts where air is used for repressuring, the returned air-gas mixture is often explosive and unfit for fuel purposes.

Flue gas can be denuded of its moisture content and used for drive purposes; this relieves most of the oxidation and explosive difficulties attending the use of air. Flue gas dissolves in oil and parallels the effect of air in that about an equal amount is soluble in oil at the same pressure. There is an attendant increase in the viscosity of the crude about equivalent to that caused by air in the same proportion. The greatest difficulty with flue gas, however, is its corrosive character which is injurious to pipes, compressors, coolers, and other metal equipment. Also, in some fields, sufficient quantities of flue gas are not available for extensive repressuring.

(g) There appears to be a lack of uniformity of opinion as to the character of flow in the sands. Data and opinions indicate that there may be viscous flow, turbulent flow, or a progressive mixture of the two, depending to some extent upon time and relative position in the reservoir. Other factors which are considered important in their influence upon the type of flow are the character of the oil, the amount of gas present, the pressure, and the size of the pore spaces through which the oil moves.

II. (1) DEVELOPMENT METHODS

Well Spacing and Rate of Development

(a) The evils of too-close spacing are principally economic. There are, however, losses of gas energy from bypassing of gas where wells are too closely spaced. Wells drilled too closely cause lessening of efficiency of expulsion of oil from reservoir sands by excessive friction. High Jamin effect results also in an early stage due to rapid drop in formation pressure, and consequently the formation of gas bubbles of increasing number and size in the vicinity of the well increases the resistance to movement of oil through the sands.

Wide spacing (within the drainage radius of wells) makes for slower drainage of sands; if operating methods are effi-

cient, there is less loss of energy consumption per barrel of oil produced and therefore a greater ultimate recovery by ordinary methods.

No set rules as to the proper spacing of oil wells can be offered for consideration at this time. Calculations of well spacing must take into account physical factors such as formation pressure, relative quantity of gas, permeability of sands, gravity of oil, position on the structure, and the relation to the edge-water line. Since these factors are not the same on any two properties, the problem of spacing wells to give the maximum efficiency of utilization of formation gas is not a matter that can be formulated and used with equal success indiscriminately.

(b) In the practical aspect, the rate of development is dependent upon economic factors, chief of which is the demand for oil. Simultaneous development of the entire structure to give all wells an equal start is recognized as theoretically most desirable. As a substitute for this impossible condition, immediate initiation of gas injection is recommended, maintaining as nearly as possible the original reservoir pressure throughout the development period.

Data on the comparative recovery from tracts equally well located on the same structure in the Burbank field in Oklahoma and leased by the Osage Indian Agency at different times show that the first tracts drilled got larger wells, better sustained production, and higher ultimate recovery than those leased and drilled one or two years later.

(c) With regard to the location of wells on structures and the efficient utilization of formation gas, it is observed that if a property under consideration occupies an entire structure and if the wells planned have considerable differences in structural elevation, it might be advisable to drill the edges of the structure first and defer the drilling of the higher portions where the relative quantity of gas is greater until the edge wells have had for some time the advantage of the full pressure of the formation gas. If this theory is correct, and it should be understood that it is purely theoretical,

it might be advisable to space wells more widely on top of the structure than on the flanks.

(d) Drilling methods should be such as to avoid unnecessary losses of gas. Casing programs should be made properly to protect all gas and oil sands, even if economically unexploitable at the time. " Blowing in " wells should be prohibited. Two wells in the Cook pool, Texas, for example, were allowed to blow wide open for days in an attempt to blow them into oil, wasting 250,000,000 cubic feet of gas and getting one 10-barrel and one 26-barrel pumping well. Efforts to convert dry gas areas into oil producing areas have caused waste of gas running into even larger figures in other areas.

II. (2) OPERATING METHODS TO BEST UTILIZE RESERVOIR GAS ENERGY

(a) *Pressure Control*

Once a well is completed the first factor in point of time and importance is that of control or maintenance of back pressure on the face of the producing sand. Proper pressure control is highly desirable on wells. Where there is no pressure control, the gas-oil ratio is much greater than where pressure control is employed. To be most effective, however, pressure control should be coöperative throughout the pool. The amount of back pressure and the means employed depend largely on the individual well.

By maintaining pressure on the face of the producing sand the several effects of rapid decline of pressure are avoided by (1) viscosity of oil being kept at a lower point; (2) the growth of gas bubbles is less, which is influential in preventing the increase of surface tension.

In many wells pressure control decreases the rate of production by lowering the pressure drop through which the expanding gas acts. This serves in the more efficient use of gas energy by lowering resistance to flow and also restrains the rapid encroachment of water, thereby preventing side-tracking of oil.

The amount of back pressure to maintain on a sand is determined by weighing the physical factors against the economic factors. If the pressure on the face of the sand is too great, possibly the gas-oil ratio may be increased due to low velocity of the fluid in the sand and increase in slippage and by-passing of gas. Also, in such cases the rate of recovery is low, particularly if the well is closely offset. As a rule, production men do not carry nearly enough back pressure on their wells to utilize the energy of the formation gas efficiently. From the physical standpoint, the most efficient back pressure will depend chiefly on the reservoir pressure, the character of the sands, the character of the oil, well spacing, and to a certain extent the relative structural position of the well.

Inefficient utilization of gas from any individual well in a lease or reservoir will affect the ultimate recovery of that lease or reservoir as a whole. Gas conservation is therefore a coöperative problem. It is recommended that wells having a higher gas-oil ratio than the average for the reservoir should be shut in to the point where the gas-oil ratio is equal to that of the average, or should be completely shut down until such time as the gas-oil ratio in the reservoir shall have changed to a point comparable to the gas-oil ratio of the higher ratio well.

The amount of back pressure to be held against producing sands decreases with the age of wells because greater resistance to flow underground requires more energy, and this energy must be applied by increasing the quantity or the expansion ratios of the gas. With decreased pressure on the sand, viscosity and friction is increased, and consequently more energy and an increased expansion ratio or greater gas-oil ratio is required.

The principal objection to back pressure control on the part of certain executives is deferment and possible loss of production. Deferred production, however, is generally recovered in a short time; generally when it is recovered, the wells produced under pressure control still have much

larger daily productions and therefore greater futures than the wells which were allowed to flow wide open.

Data on the effect of future production of shutting in wells show the following:

(a) Considering fields as a whole, ultimate production is probably not decreased. Deferred production is obtained usually within two or three years.
(b) In certain fields in the San Joaquin Valley in California it was found that some of the properties on top of structures suffered from drainage due to gravity. The gas pressure in those fields was very low, and consequently the oil drained down the flanks of the structure by gravity.
(c) Evidence from experience in the Torrance field, Calif., indicates that in small areas, deferred production may never be recovered, especially in fields where the gas is the prime production factor and when adjacent properties continue to produce.
(d) All the evidence indicates that any shut down must be coöperative throughout the structure in order to be successful.

The principal means available for pressure control in a flowing well are:

1. Restriction of flow by flow beans or orifices at the casing head or at the bottom of the tubing,
2. Size and depth of tubing,
3. Stopcocking, or part time operation,
4. Variation of pressure and quantity of circulated gas in case of gas-lift wells.

Pressure control is possible for pumping wells through:

(1) Regulation of fluid level by:
   (a) Location of pump,
   (b) Intermittent pumping,
   (c) Varying length and speed of strokes.
(2) Regulation of gas pressure by:
   (a) Shutting in gas either at all times or when well is not being pumped (in effect, stopcocking).

Other beneficial effects of pressure control in addition to better utilization of reservoir gas energy are:

(a) Retardation of water encroachment,
(b) Longer flowing life and probability of lower operating costs,
(c) Minimum sand trouble where wells are apt to make much sand.

(b) *Gas and Air Lift Methods*

The gas, or air lift, is a mechanical method of supplementing the reservoir energy by assisting in lifting the oil from the bottom of the well to the surface. The formation is thus relieved of a certain expenditure of gas energy which possibly might be put to better use in bringing more oil into the well. Field data indicate that the gas lift should be installed in a well immediately prior to the period when the well "heads." Some data show that it is inadvisable, at least in the town-lot areas in California, to install the gas lift in wells whose production can be handled with a standard oil well pump. In other words, wells whose production is less than about 200 barrels a day will have a more efficient gas-oil ratio and lower lifting costs usually, when pumped "on the beam."

Efficient operation of a well, whether the wall is flowing naturally, on the gas lift, or pumped on the beam, requires that the amount of gas produced with the oil be known. This knowledge is a fundamental necessity in oil production. Without this knowledge, conclusions as to the effect and use of gas must be drawn blindly.

(c) *Gas Injection*

The importance of gas injection, in one or more of its various phases, is recognized as perhaps the outstanding feature of the moment in oil production. Gas injection should, wherever possible, begin in the early stages of development—that is, should be of the pressure-maintenance

type. Data presented tends to minimize the difficulties of high pressure injection. Attention is called to the fact that only a relatively small amount of additional work is necessary to carry on the compression from 600 pounds' pressure up to pressures of 1,250 or 1,500 pounds per square inch.

In this connection, the use of double gas separators or gas traps is recommended to save compression costs. The high-pressure trap might be kept at 250 to 300 pounds' pressure, thus saving a large part of the work of recompression; the gas remaining in the oil discharged from the first trap is then released from the oil in a low pressure separator.

Early installation of pressure maintenance is put forward as a means of avoiding the necessity of immediate development, beyond the needs of the country for oil; if the reservoir pressure be maintained, an orderly development program could be followed and the later wells would have initial production approximating that of the first wells drilled.

Of the gases available for repressuring, natural gas of the original composition is most desirable if true repressuring is desired, the gas being returned without the extraction of the gasoline fractions. Flue gas and air follow in preference in the order named. Where the only object is gas drive, the extraction of the gasoline is considered unimportant by some engineers, while others hold that the heavier hydrocarbons are needed to help "wash off" the oil adhering to the sands.

The injection of gas into depleted or partly depleted oil reservoirs is a means of storing surplus gas at times when markets for gas are not available. Although it is not known what proportion of the injected gas can be recovered later when a market for gas exists, operators in California are of the opinion that the cost of injecting and storing this gas will be returned at a profit sufficiently large to warrant current expenditures for such storage. The fact that nearly

50,000,000 cubic feet of gas was stored daily in certain California fields in the summer of 1928 shows that operators are sincere in their belief that gas injection is a conservation measure which offers several opportunities for success and profit.

The operation of producing wells by gas injection differs in no important way from best practice in the case of natural flow unassisted by injected gas.

(d) *The Gas-Oil Ratio as an Operating Guide*

The importance of a proper conception of the value of the gas-oil ratio as a measuring stick of production efficiency is stressed, and in this connection attention is called to the often neglected pressure factor. Pressure is as fundamental as volume. Obviously the force exerted by 1,000 cubic feet of gas under, say, 100 pounds' pressure is far less than the force exerted by the same quantity of gas under a pressure of 1,000 pounds per square inch. The fundamental factor is the combination of pressure and volume, which together make the force exerted by the gas. It is the force that is important. In comparing production methods at the same well, the volume alone can be used as the index, for the underground pressure will be the same; but when comparing production efficiencies in two or more wells, or in wells at different fields where conditions cannot be exactly alike in all details, the index should include both pressure and volume.

III. ADVANTAGES OF AN IDEAL COÖPERATIVE DEVELOPMENT PLAN

Among the more important advantages of an ideal coöperative development plan, with particular reference to proper utilization of reservoir gas energy, are the following: (1) A carefully planned development program is made possible, by which unnecessary offsets, too close spacing, and other evils of competitive drilling may be avoided; (2) overproduction in any one area is prevented, making proration or shutting in of production easily accomplished;

(3) the shutting in of wells which have excessively high gas-oil ratios is made possible, the application of gas injection processes can be made at the best points without regard to lease boundaries, and uniform pressure control can be exerted without danger of loss of production; (4) exchange of information is facilitated and the most efficient engineering control is made possible at moderate cost. Aside from the advantages directly concerned with the conservation of reservoir gas energy it will (5) make possible the reduction of overhead and operating costs through the reduction of personnel and elimination of duplication of equipment; and (6) facilitate repair work on wells and means to combat water encroachment.

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